Training Programme for IAS Officers

October 15-19, 2001

Reforms in Energy Sector

Organised by

Tata Energy Research Institute
Darbari Seth Block, Habitat Place
Lodhi Road, New Delhi – 110 003

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Programme schedule for IAS Officers Training on Reforms in Energy Sector (October 15-19, 2001)

Day/Session	09:30 - 11:00			11:30 - 13:00		14:00 – 15:30		16:00 - 17:30
Monday (15.10.01) ***Power***	**10:00 - 10:30** Registration	**10:30 - 11:00** Welcome and Introduction	T	Energy Sector Overview *Mr P V Sridharan, Fellow, TERI*	L	Reforming the power distributions *Mr Partha Mukhopadhya, Vice President, IDFC*	T	*Library Session and TERRAVIEW*
Tuesday (16.10.01) ***Power***	Draft Electricity Bill 2001 – a review *Mr K Ramanathan, Fellow, TERI*	**11:00 - 11:30** *Tea & Photograph*	E	Securitisation of SEB dues *Mr R Ramanujan, Joint Secretary, Ministry of Power*	U	Californian power crisis *Mr Prabir Purkayastha, Delhi Science Forum*	E	Panel discussion – Future of power sector reforms *Mr S C Mahalik, Former Chairman, OERC* *Mr V Raghuraman, Senior Adviser, CII* *Mr K Ramanathan, Senior Fellow, TERI*
Wednesday (17.10.01) ***Field visit***	**10:00 a.m. onwards** *Visit to Distribution Utility, NPCL at Noida*				N			
Thursday (18.10.01) ***Renewable/ Coal***	Renewables – prospects and policy reforms *Mr A K Mangotra, Joint Secretary, MNES*		A	*Reforms – impact on rural electrification* *Ms Akanksha Chaurey, Fellow, TERI*	C	Energy reforms and poverty reduction *Ms Rekha Krishnan, Research Associate, TERI* *Ms Divya Dutt, Research Associate, TERI*	A	Regulatory framework for the coal sector - a review *Mr P V Sridharan, Fellow, TERI*
Friday (19.10.01) ***Oil/Gas***	Restructuring of the oil and gas sector – an update *Mr R K Batra, Distinguished Fellow, TERI*			Regulatory framework for the oil and gas sector *Mr Nirmal Singh, Senior Fellow, TERI*	H	**14:30 – 15:00** Course evaluation/ valedictory session		

List of Faculties

Internal

Mr R K Batra
Distinguished Fellow
Policy Analysis Division

Dr S K Sarkar
Senior Fellow
Regulatory Studies and Governance Division

Mr K Ramanathan
Senior Fellow
Regulatory Studies and Governance Division

Mr Nirmal Singh
Senior Fellow
Regulatory Studies and Governance Division

Mr P V Sridharan
Fellow
Policy Analysis Division

Ms Akanksha Chaurey
Fellow
Energy – Environment Technology Division

Ms Rekha Krishnan
Research Associate
Policy Analysis Division

Ms Divya Dutta
Research Associate
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Energy Sector

Indian energy sector: an overview

Energy–economy linkages

As elsewhere in the world, the energy sector in India too is closely linked to developments in the economy. Between 1970 and 1995, energy consumption and GDP (gross domestic product) were observed to be highly correlated at 0.97. While economic development has influenced the pattern of energy consumption, energy–GDP elasticity has been falling — the elasticity of over 0.5 in the 1990s is just one-third that was seen in the 1950s (Figure 1). Reasons for this decline include changes in technology and in demand patterns for various energy sources. Figure 1 also shows that the energy—GDP elasticity curve for India closely follows the coal—GDP elasticity curve, indicating the continued predominance of coal in the Indian energy sector (as seen in Figure 2).

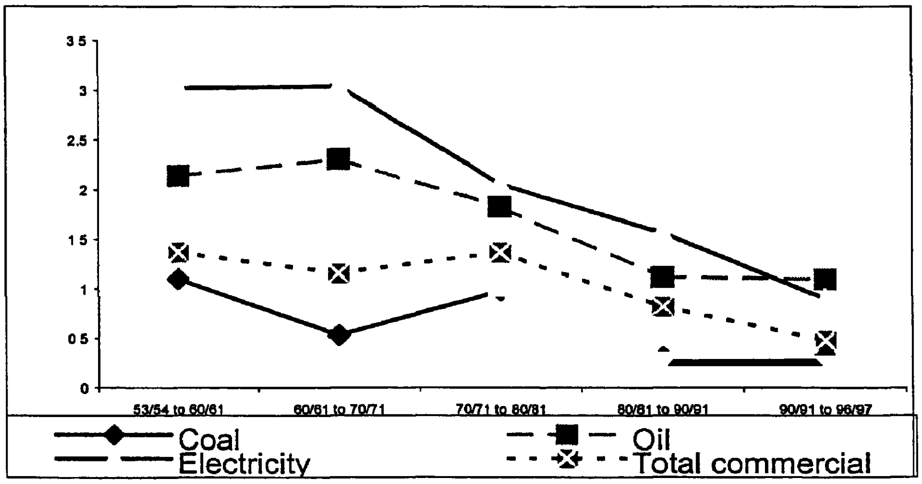

Figure 1 Elasticity of final energy consumption with gross domestic product

Energy intensity has been seen to follow a certain pattern the world over. As the economy grows, energy intensity rises following increases in energy consumption. However, beyond a certain level of per capita income, energy intensity begins to decline. India's energy intensity of GDP is about 3 times the world average.

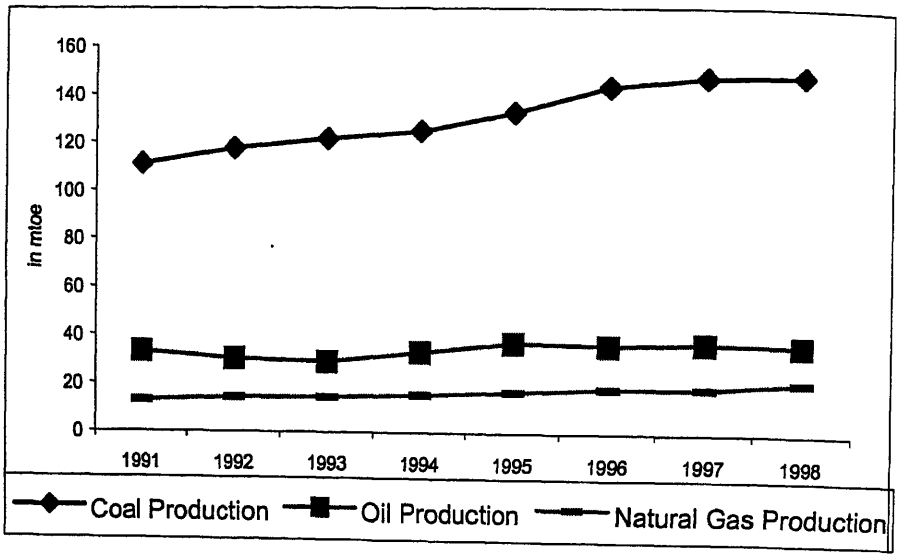

Figure 2 Trends in production of coal, oil, and natural gas

These linkages between energy and economic factors, manifested in energy–GDP elasticity and energy intensity of GDP can be traced to

- demographic changes including relatively faster growth in urban areas, higher per capita GDP, and per capita gross saving
- penetration of more efficient end-use devices (improved *chulhas*, for instance)
- technological improvements in conversion equipment (more efficient power plants)
- inter-fuel substitution with more efficient alternatives. (Kerosene and liquefied petroleum gas have substituted soft coke in households. Diesel and electric traction have replaced steam traction in the Railways. Natural gas is increasingly being used as fuel and feedstock in the fertilizer, petrochemicals, power, and sponge iron industries as well as in the transport sector).

Energy supply

India is the third largest producer of coal, with nearly seven per cent of the world's coal reserves. Non-coking coal makes up 86% of the total reserves of 211,593.6 MT (up to depth of 1200 m) (Table 1). Indian non-coking coal generally has low calorific value and high ash content and opencast mining tends to deteriorate the quality of coal further.

In the oil and natural gas sector, despite a continuous decline in balance recoverable reserves, India continues to be one of the least explored regions with just 30% of its estimated reserves explored so far.

Table 1 Energy supply indicators: 1999/2000

Reserves / Production	Coal (million tonnes)	Oil (million tonnes)	Gas (billion cubic metres)	Power
Reserves	211593.6[1]	715	675	-
Installed capacity	-	-	-	97837 MW
Production / generation	292.27	32.72[2]	27.43[3]	451 billion units

[1] coal reserves up to depth of 1200 metres; [2] crude oil production only, petroleum products production 64.55 million tonnes; [3] gross production includes flaring, etc.

Over the years, domestic availability of crude and petroleum products has not kept pace with consumption. But in and after 2000/01, the situation for petroleum products is expected to improve considerably with additions to refining capacity. The growing demand for natural gas will have to be met from imports in the form of liquefied natural gas.

India's power sector draws upon coal and petroleum products as well as the country's resources of uranium, wind energy, and hydropower. India has 34 000 tonnes of uranium resources of which only 44% is economically exploitable. The total potential of small hydro (up to 15 MW capacity) and wind energy in the country is estimated at 10 000 MW and 20 000 MW, respectively.

The total installed capacity of power in India as on 31 March 2000 was 97 837 MW, comprising 71% thermal, 25% hydro, 3% nuclear, and 1% wind. Despite growth in power generation over the years, India continues to face power shortages. The quality of power too continues to be poor. Voltage fluctuations, frequency problems, and supply interruptions are rampant.

There are concerns attached to the key sources of power generation, coal, and hydel. Thermal power generation from coal is limited by the quality of coal, transportation constraints, and environmental concerns. Though hydel power seems to be the best option, most of the unexploited potential is located in difficult/inaccessible areas and socio-political issues such as interstate cooperation and dislocation of population need to be tackled.

The potential for renewable energy technologies – biogas; improved cookstoves; biomass; solar energy; wind energy; small hydropower; ocean energy; and energy from urban, municipal, and industrial wastes – is immense. Currently, India's renewable energy programme is one of the world's largest and most diverse. Grid quality power from renewables is now a reality. In fact, installed capacity of power based on renewables represents over 1.5% of the total installed capacity of power. Of these, wind is the most important and India's wind power capacity of 1155 MW is the fifth largest in the world.

In addition to commercial fuels – coal, oil, natural gas and power – India consumes large quantities of traditional fuels. The traditional energy sector is not well documented. Firewood, chips, and dung cake constitute the primary source of energy for cooking in over 90% of rural households across income classes. These fuels are also used for water heating and space heating. Traditional fuels are also an important source of energy in over 30% of urban households and their use is most prevalent among the lower income categories. Draught animal power continues to be used in farming and for transportation in villages and in small towns.

Traditional fuels are often classified as 'non-commercial' sources because they are mostly gathered or collected from the neighbourhood. While this is true in rural areas, urban poor who use these fuels pay heavily for fuelwood and the prices varies significantly across regions, being particularly high in large cities.

Energy consumption

India's commercial energy consumption is just one-fourth that of the world average. It is not surprising, therefore, that India's consumption of coal, oil, and natural gas is a small part of world consumption. The consumption of commercial fuels is steadily rising throughout the Indian economy, with coal continuing to be the most prominent energy source (Figure 3).

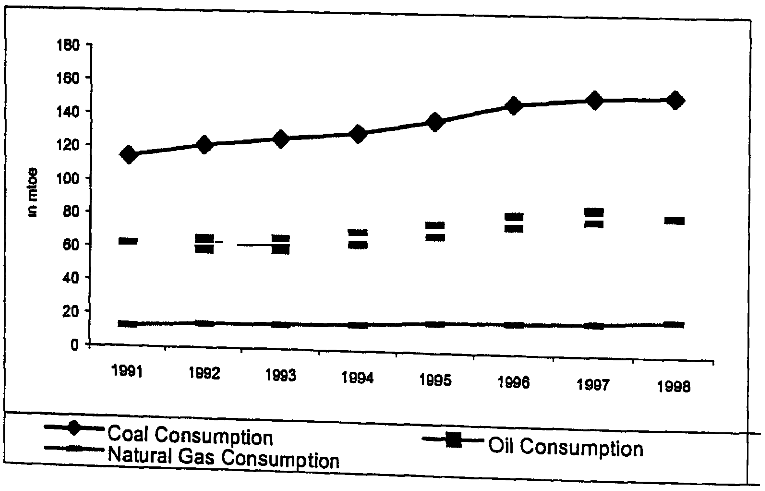

Figure 3 Trends in consumption of coal, oil and natural gas

Table 2 Sectoral energy consumption by fuel: 1998/99

Sector	Coal (%)	Petroleum products (%)	Natural gas (%)	Power (%)	Total (%)
Agriculture	0	10	1	89	100
Industry	73	13	3	11	100
Transport	0	99	1	0	100
Domestic	0	72	1	27	100
Others	0	71	17	12	100

Source. TERI estimates

The fuel composition of commercial energy consumption varies significantly from sector to sector (Table 2). Coal continues to meet over 70% of industry's energy needs, but petroleum products and power are replacing coal in small quantities. In agriculture, draught animal power continues to be used in various farming activities, but this is not well documented. In transportation, the use of coal is virtually nil following the substitution of steam traction with electric traction. Consequently, the use of power has gone up. The consumption of petroleum products has increased following a sevenfold increase in registered motor vehicles between 1981 and 1997. While a large part of the household sector continues to depend on traditional fuels for cooking, this is not documented formally. There appears to be some substitution of petroleum products by power in the household sector. This could be the result of more extensive electrification whereby kerosene gets replaced by electricity for lighting.

Energy security

The demand for energy in India has been growing rapidly and India continues to be a net importer of energy. India imported 39.81 million tonnes of oil and 17.38 million tonnes (net imports) of petroleum products in 1998/99. India is also expected to import natural gas to meet its growing gas requirements. Projections of crude imports indicate that import dependence, which is 66% at present, will rise to 80% by 2010.

Evidently, the issue of energy security looms large. Nevertheless, some developments in the Gulf region are encouraging. As more and more private oil and gas companies invest in this region, it is hoped that the diversity of suppliers would result in more competition in the industry. Also producers and consumers are now being integrated with suppliers making downstream investments in consuming countries. These developments are likely to bring about more stability in supplies and prices. Energy security is not limited to ensuring smooth supplies of energy at reasonable prices. It also entails production and use of energy in a manner that is least damaging to the environment and promotes sustainable development.

Energy - environment interface

The environmental implications of energy use arise primarily out of the fact that worldwide, nearly 90% of the primary energy consumption comes from combustion of fossil fuels. Utilization of less polluting renewable energy forms has been relatively low. The most direct impact of fossil fuel use is an increase in air pollution levels, particularly in urban areas with expanding vehicular population. Use of fossil fuels also produces greenhouse gases, increasing the threat of global warming.

Several measures have been taken up for environmental management. These include setting up of standards and regulations for ambient air quality, drinking water, industrial emissions, vehicular emissions, industrial effluent discharge, hazardous waste and bio-medical waste. Measures in the area of vehicular pollution abatement include use of less polluting fuels (including low sulphur diesel, unleaded petrol, and compressed natural gas); vehicles with catalytic converters; and regulated movements of trucks. Managing rapid energy demand escalations through rational energy pricing, more efficient energy production and utilization, taxation and rationing is a must. Costs of environmental degradation will have to internalized, and environmental and socio-economic impact assessment will need to be built into project planning and development.

These efforts will have to be accompanied by fuel substitution initiatives that reduce dependence on oil imports and favour greater use of indigenous energy resources. Resources that could be taken up for substitution include abundantly available indigenous resources of renewable energy and coal.

Initiatives on the energy sector

Over the 1990s, there has been a flurry of regulatory reforms in the Indian energy scene. While coal prices have been deregulated, the administered pricing mechanism is being dismantled in the oil and gas sector. The power sector has witnessed initiatives towards unbundling and gradual corporatization of state electricity utilities and the setting up of regulatory commissions. There has been increased private participation in all sectors.

India is perhaps the only country in the world with an independent ministry for the promotion of renewable energy technologies. The thrust of India's renewable energy programmes has been on market development in order to facilitate and catalyse commercialization. This has resulted in increases in the diffusion of renewable energy technologies. The government has also initiated steps towards regional co-operation in energy from neighbouring countries (e.g., hydropower from Bhutan and Nepal, possibility of natural gas supplies from Bangladesh).

A policy shift towards relatively less energy-intensive industries also helps mitigate, to an extent, the concerns of energy security.

There is an urgent need for an integrated energy policy for the country that explores various options in sustainable energy development, taking into account socio-economic factors, environmental impacts, and energy security issues.

Privatise yes, but the state must still regulate.

S Sundar and S K Sarkar[1]

The decade of 1990s saw the liberalization and privatization of infrastructure services in a big way. For many years, there was a strong belief that infrastructure services can only be provided by natural monopolies as they alone enjoyed economies of scale. And whether the monopolies were in the private sector as in the US or in the public sector as in Europe and India, the service providers had the opportunity to set prices without providing commensurate value for money. There was also the belief in many countries, including India, that only the public sector could provide infrastructure services efficiently, that the entry of the private sector should be restricted, if not altogether prevented, and that the Westminster style of accountability of the public sector is adequate to ensure efficiency and protection of consumer interests. As a result, government was both the service provider and policy maker in various sectors such as electricity, telecom, ports, water, etc. Thus, in the absence of competition, operational inefficiencies, poor quality of services, and inefficient allocation of resources were common in the provision of infrastructure services.

The inability of the infrastructure sector to deliver services in an efficient and cost effective manner led to a reassessment of the performance of these sectors in many countries including India and it was felt that commercialization of the sector could improve efficiencies and reduce costs in delivery of infrastructure services. There were also certain pragmatic and non-ideology related factors such as the need to attract additional investment in infrastructure from the private sector, the need to build quality infrastructure to remain globally competitive, advances in technology that made vertical and horizontal unbundling of services possible, and ability to access capital from across borders which compelled governments to resort increasingly to the privatization and commercialization of infrastructure services.

Even with the commercialization of infrastructure services, and the prospects of competition, the market structure in infrastructure services tends to retain a monopolistic element in most countries. For instance, in UK, at the time of privatization of electricity industry (1989/90), the market share of National Power and Power Gen, the power generation companies in UK, was almost 78 percent. In India 95 percent (March 2000) of power generation, and almost all transmission and distribution are in the public sector. In order, therefore, to prevent exploitation by monopolies, governments had to continue to protect consumer interests. There was also a need to create a level playing field between monopolistic incumbents and new entrants. Further, the process of commercialization itself led to high transactions costs, which had to be mitigated. All this called for expertise which government did not possess. Besides, as governments and their agencies continued to be providers of infrastructure services, and as they themselves had to be regulated, there was a need for a mechanism outside governments, with adequate expertise and flexibility to regulate all players, ensure efficiencies and protect consumer interests. In short, there was a need for a new type of governance which is what independent regulation seeks to provide.

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[1] The authors are with the Tata Energy Research Institute, New Delhi. Published in the Times of India, Government Business (page vii), New Delhi. May 18, 2001

The advantages of this 'new governance' are many. It makes the decision making process consultative and transparent, takes into account the views of various stakeholders during the regulatory process thereby reducing compliance costs, makes available services at affordable prices through creating or mimicing competition, sets quality of services standards, facilitates private sector participation in the infrastructure sector, and makes the sector sustainable through tariff reforms. The benefits of independent regulation are beginning to show up in India. Competitive prices in the telecom industry, rationalisation of tariff and reduction in T&D losses in the electricity sector are some examples.

At the central level, the telecom regulator, TRAI (Telecom Regulatory Authority of India) was created in 1997, the port regulator, TAMP (Tariff Authority for Major Ports) also in 1997, and the CERC (Central Electricity Regulatory commission) in 1998. At the state levels, the electricity regulatory commissions in Orissa in 1996 and thereafter, in thirteen other states have been so far eatablished. They are autonomous, accountable for their actions, and have powers to ensure implementation of their orders and directions. Their functions include mandatory functions such as tariff regulation, recommendatory functions such as licensing as in the telecom sector, and advisory functions such as sector restructuring. The specific scope of regulation differs across sectors. An interesting feature of these new institutions is that they are neither administrative bodies nor judicial bodies. The decision making process of these institutions is mandated to be transparent and consultative unlike decision making in government departments which is usually opaque. They enjoy a quasi-judicial status, but unlike the judiciary which applies the law to facts, they are required to balance the interests of different stakeholders, and promote the development of the sector through the regulatory process.

Most Indian regulators have accorded priority to tariff setting of various services and are yet to address their other functions. The telecom regulator rebalanced the tariff of various telecom services for the first time in 1999 through its tariff order, which, inter alia, increased the local call charges and rentals while reducing the long distance and international call charges in a phased manner. Similarly, the electricity regulators in states such as Orissa, Uttar Pradesh, Maharashtra, Gujarat, Rajasthan, Andhra Pradesh, Haryana and Karnataka have passed tariff orders which, in general, seek to rationalise tariff, reduce the cross subsidy across consumers, and align tariff with the cost of supply of power. The central electricity regulator has also stipulated availability based tariff for the central generating stations, and a grid code for enforcing discipline in the national grid.

Another area where some regulatory initiatives have been taken is setting standards of quality of services. The Orissa electricity regulator has taken the lead in this area by setting such standards, and the other electricity regulatory commissions are yet to follow. The telecom regulator has also issued a regulation laying down standards for various telecom services. The impact of these regulatory interventions could have been visible had there been a mechanism for compensating a consumer if such standards of services are not met by the regulated utilities. In Sri Lanka, for example, failure to meet standards in telecom services automatically results in payment of compensation to the consumers.

India's infrastructure regulators face many constraints such as start up difficulties, lack of experienced personnel, inadequate information or non availability of quality data, lack of clarity of certain provisions of regulatory legislation, resistance from the government, lack of training facility on various regulatory issues, etc. Regulatory reforms can not progress unless the sector concerned are restructured and the archaic legislation governing the infrastructure sectors are revamped. And finally, the extent of government's commitment to regulatory reforms coupled with how quickly the regulatory authorities earns legitimacy will determine the degree of its success in the coming years.

Regulating relationships

S Sundar and S K Sarkar[1]

Independent regulation invariably involves transfer of powers and functions once exercised by governments to autonomous statutory agencies whose status in government is not clearly defined. This has naturally caused friction between ministries and regulatory authorities, and has resulted in a debate on the relationship between the government and the regulators.

Regulators have kept their distance from governments and have been particularly anxious to demonstrate that there is no regulatory capture by the governments. There are others who feel that in the interest of sectoral development there should be close consultation between the regulator and government as it happens in the U.K.

Regulatory independence or autonomy cannot be secured merely by establishing regulation through legislation. It is also necessary that the legislation should contain appropriate provisions in regard to appointments, removal from office, freedom to appoint staff, ,financial autonomy etc to ensure regulatory autonomy.

For example, look at the provisions relating to the appointment of the members of the regulatory authorities. In the case of TRAI and TAMP, appointment of chairman and members is entirely the prerogative of the executive; in the case of CERC, the law requires the government to choose the chairman and members from a panel prepared by a search committee. Clearly, if the appointment of a regulator is to be at the mercy of the executive, the regulator's independence could be questioned.

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[1] The article was published in the Times of India/ Government Business (p v) on June 1, 2001, New Delhi.

This is also the position in regard to the authority for the removal of members. The manner in which a member can be removed varies across sectors. Consultation with the Supreme Court is mandatory in the case of the Central Electricity Regulatory Commission. .There was a similar position in the TRAI Act of 1997 which was removed when the Act was amended through an Ordinance in 2000. Government is now free to remove the chairman and members of the telecom regulatory authority at will which is what it did in 2000 when it sent home six out of seven members.

A regulator should be autonomous, but regulatory autonomy does not mean that the regulator would not be bound by the policy of the government in office Since the government has been elected by the people, and is responsible to Parliament/legislature, it is the best judge of public interest, and best equipped to lay down "public policy". Governments, should , therefore, have the power to issue policy directives as appropriate to the regulators, and this has been provided in all the regulatory legislation in India.

However, public policy has not been clearly defined anywhere. The Indian courts have also been extremely reluctant to define public policy narrowly, and have generally taken the view that it is for the government to decide what is a public policy. It is, therefore, logical that governments should have retained the right to determine policy, and issue such directives as are necessary to the regulators to convey public policy.

There are ,however, limitations, both in law and in equity, on the extent to which governments can alter public policy, or issue policy directives to the regulators. Policy directives to a regulator should conform to the objectives of the relevant regulatory legislation. Governments must take extreme care to ensure that these directives do not relate to what are clearly "administrative and technical matters" and are strictly "policy in nature". Governments must also ensure that any change in public policy would have to stand the test of "Legitimate Expectation" both in a procedural and substantive sense, and the concept of "Promissory Estoppel". Thus, while the regulator is bound by the public policy of the government, the formulation of public policy has to be within the confines of the limitations set out above.

Equity, also, demands that while governments can issue policy directives, they must invariably consult the regulators before such directives are issued. In fact, this has been made legally binding in the telecom and ports regulatory legislation, although consultation has been required only " as far as practicable". In the central legislation in the electricity sector, no provision at all has been made for consultation. Eventually, as the process of regulation matures in India, as it has in the UK, there should be no need at all to issue directives, and there should be close consultation between the governments and regulators. But as long as the need for the issue of policy directives remains, it is essential that the regulator should be invariably consulted and his views respected. And, it is equally important that the directives issued, and the reasons therefor should be made public.

Since the definition of a public policy is imprecise, and what constitutes public policy can be contested, legislation in some states have provided for a mechanism to refer the question as to whether a directive is a policy directive or not to a third party. Decision as to whether a matter is a policy matter or not, is essentially a judicial, and not a technical decision, and should, therefore, be left to the sitting judiciary to decide. Besides, such a reference to a third party takes away the legitimate power and role of the High Courts and the Supreme Court, as envisaged in our legal system. It also takes away the Court's jurisdiction to strike down a policy directive if it was violative of law.

A policy direction was issued in recent times in India's telecom sector in the context of the implementation of the telecom tariff order in March 1999. On March 12, 1999, the Government issued a direction keeping the tariff order in abeyance, as the order allegedly did not protect the low-income users. The regulator then requested the Government to clarify the basis for the direction issued, which clarification was never provided. The matter was later " amicably " settled. But what this episode demonstrates is that government did not bother to follow the provisions of law, and failed to respect the independence of TRAI.

A healthy relationship between the regulator and government should evolve over time. and there should be close cooperation between the two as regards the development of the sector. Governments should respect the regulatory bodies and seek their expert advice on all issues relating to the sector. Simultaneously, the regulators should earn legitimacy through transparency, better communication strategy, building unquestionable regulatory expertise, and willingness to work with government and other stakeholders to promote the development of the sector they regulate.

Regulators can't pack a punch without financial muscle.

S Sundar and S K Sarkar[1]

A constructive relationship between government and the regulator is essential for the success of regulatory reform. Such a relationship can develop only when governments empower the regulators so that they can hold their own. It is, however, not easy to empower the regulators. Bureaucracies all over the world do not willingly give up the powers that they enjoy. Most countries have sought to provide for regulatory autonomy by setting up the regulators through specific legislation. In India too, where the bureaucracy is powerful, regulation has been established through legislation in order that the regulator's autonomy is not left to the magnanimity of the bureaucracy.

However, legislation alone cannot ensure autonomy unless the legislation provides for certain essential safeguards to ensure autonomy. Safeguards that have been considered essential the world over are a transparent selection process, clearly stated qualification and disqualification criteria, prescribed tenure, freedom to obtain expertise and authority to incur expenditure independent of government approval, and finally criteria for removal.

All the regulatory legislation in India provide for qualification criteria for selection of regulators, and these invariably include sufficient experience in economics, finance, law, administration, consumer affairs, or industry. Sector experience has not been considered essential.

At present, a majority of the chairmen of regulatory bodies are either retired civil servants or judges. It is often argued that since regulatory authorities exercise the functions and powers which were earlier vested in government and enjoy quasi-judicial powers, they are best manned by persons who have served in government or the judiciary.

But regulators are neither fish nor fowl; they are not the government and certainly not the judiciary. And their mandate extends beyond tariff setting to taking measures as are necessary to introduce competition, increase efficiency, provide quality of service standards etc. These call for a thorough knowledge of the sector and a vision for its future, and both these qualities are not necessarily possessed only by retired civil servants or judicial officers. They can also be found in the industry, amongst professionals, and the academia, but the process of selection and conditions of service do not encourage a wider selection.

All the regulatory legislation contain provisions that restrict the scope of employment of regulator once he demits office, and this discourages younger and competent people from the industry and professions from accepting appointments as regulators. The post of Chairman, CERC which has been vacant since February 2001 was reportedly offered to a highly reputed professional in the electricity industry and was turned down.

All the regulatory legislation in India provide for a fixed tenure for the regulators. The tenure is normally five years subject to an age restriction. So far, early termination of regulators' tenure has occurred only in the case of TRAI where six of its seven members were removed from office when the Authority was reconstituted through an

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[1] The authors are with the Tata Energy research Institute, New Delhi. In Times of India, Government Business (page v) June 22, 2001

ordinance in 2000. Interestingly, the port legislation has a provision for superseding the TAMP.

A regulator cannot be independent unless he enjoys both financial and organisational autonomy. The Indian regulators, unfortunately, enjoy neither. CERC and the state electricity regulators such as OERC have to depend on the government for determining their annual budgets. CERC's budget is charged to the Consolidated Fund, but this does not provide for autonomy as CERC has to seek government's approval for incurring expenditure on individual activities. TAMP is wholly dependent on government for its budget. The TRAI Act provides for a Regulatory Fund, which TRAI can administer. But this fund is yet to be established and TRAI continues to depend on government for funding.

One of the reasons for establishing regulatory authorities outside government was that they could draw expertise from the market which governments cannot at civil service salaries. Unfortunately, the regulators in India are not free to hire staff of their choice at salaries they command. The result is that regulatory authorities are largely manned by staff drawn on deputation from government or the regulated public utilities. Given their background and mind set, they lack a commitment to the regulatory cause and suffer from a conflict of interests. Training of regulatory staff, thus, assumes great importance.

The regulator clearly should have powers to call for information, and conduct an inquiry into the working of any service provider and issue such directions as are necessary for the proper functioning of the service providers. While TRAI enjoys these powers, they are not available to TAMP or CERC. The regulators should also have access to reliable data, and this is particularly important for tariff setting. The data mostly rests with the regulated entities, and is not always reliable. Regulators should, therefore, have powers to prescribe the accounting standards and information systems that the regulated entities should adopt.

The legislation that envisages independent regulation should also provide for all the safeguards necessary to ensure autonomy. The Indian legislation have not gone far enough in this direction largely because there has not been a coherent policy on regulation. Drafting of the legislation in each sector has been left to the Ministry concerned, and the ministries have been reluctant to let the regulators become independent. It is now time for government to identify the lacunae in the legislation and initiate changes in order to empower the regulators.

Empowerment of the regulators is a necessary but not adequate condition to improve regulatory governance. In the United States, infrastructure services were largely provided by the private sector, and independent regulation became necessary to regulate private monopolies and oligopolies. The situation in India is different. Infrastructure services have so far been largely provided, and continue to be provided, by the government and public utilities like VSNL and MTNL in the telecom sector and the SEBs in the electricity sector. Independent regulation is all the more difficult when the regulated entities are powerful, government owned entities. It is, therefore, necessary that even as regulators are empowered, regulatory reforms should be accompanied by the restructuring of the public utilities and their privatization.

Accountability helps regulate the regulators

S Sundar and S K Sarkar[1]

In our last article, we had argued the case for empowering the regulator. An autonomous regulator must, however, be accountable for his actions. It is only regulatory accountability that would make independent regulation acceptable to all stakeholders, especially the government.

Clearly, the regulator must be subject to public policy as laid down by government in office. And the Supreme Court has more than once held that what is public policy is best left to the government to decide. The exercise of regulatory discretion is also constrained by the government's right to issue policy directives to the regulator, which right is contained in all the regulatory legislation. Thus the apprehension that ministerial control over the regulator has been diluted in the new set up is not correct. Nevertheless, it has not to be borne in mind that in a Parliamentary democracy, the minister in charge is ultimately responsible for all the decisions and actions that impact on the sector that he oversees. And it is the government through Parliament that has transferred its various powers to the regulators. The regulators should, therefore, recognize this ultimate responsibility of the ministers, and consult with him or at least keep him informed as in UK, without compromising regulatory independence.

The larger issue is how to make the regulator accountable to the Parliament. In UK, for example, procedure for Parliamentary oversight over regulatory activities has been established over the years. The Parliamentary Select Committee in UK oversees the regulatory activities, conducts inquiry involving into the regulated industry, and calls for witnesses from regulated entities, the regulator, and consumer groups. The oral hearings are made public. Although the Committee has no formal powers to issue directives to a regulator or a regulated entity, its observations are given sufficient importance: the regulator has to prepare a formal response to their observations. In case the regulator does not agree with the views of the Committee, the reasons for not doing so have to be recorded. In short, the relationship provides for Parliamentary supremacy without undermining regulatory autonomy.

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[1] The authors are with the Tata Energy Research Institute. In the Times of India, Government Business (p v) July 6, 2001.

The procedure for Parliamentary oversight over the regulator has yet to be established in India. The Standing Committee on Energy recently reviewed the working of CERC and questioned CERC's decision on availability based tariff; the Committee further directed the government to review the entire gamut of work of CERC. While the Committee's right to comment on the working of CERC cannot be questioned, it would have been appropriate for the Committee to have heard the CERC before passing comments on its working. It is important for Parliamentary Committees and regulators to understand and respect each other's work. The legislative provisions for audit of accounts and expenses of regulatory authorities by the C&AG is yet another measure to ensure regulatory accountability. And here again, the C&AG's role should be carefully defined so that his scrutiny does not extend into substantive decisions of the regulators.

Transparency in decision making is another effective mechanism to ensure accountability. Fortunately, the need for transparency in decision making has been recognized and mandated by the legislation in the telecom and electricity sectors. In the port sector, TAMP on its own has adopted this process even though there is no legislative requirements. Regulators in India either hold quasi judicial hearings as in the electricity sector or go through a process of consultation as in the telecom and port sectors. In some cases, a combination of the two processes has been practised. Both the quasi judicial and consultative processes ensure that the stakeholders are provided with every opportunity to be heard. This apart from ensuring transparency in decision making provides a forum to vet the quality of data, and reduces the cost of regulatory compliance.

Further, steps to enhance transparency could include measures to make the thinking of regulators known to the stakeholders. Regulators, for instance, could make their draft regulatory orders public, obtain the views of stakeholders on the draft, and then, pass final orders. Such a procedure would considerably enhance the quality of regulatory decisions, make them more acceptable, and reduce the costs of compliance.

That regulatory decisions can be contested in appeal is another measure to ensure that regulators do not misuse their powers. All regulatory legislation in India provides for appeals against regulatory decisions to the High Courts as in the electricity sector, or to a special Tribunal as in the telecom sector. Many of the regulatory decisions have in fact been challenged in the courts. The appeals filed by NTPC/PGCIL against CERC's tariff orders, and the reference filed before TDSAT against the TRAI's recommendation on the limited mobility are some examples. These appeals go to remind the regulators that their decisions are not necessarily final , and therefore cannot be arbitrary.

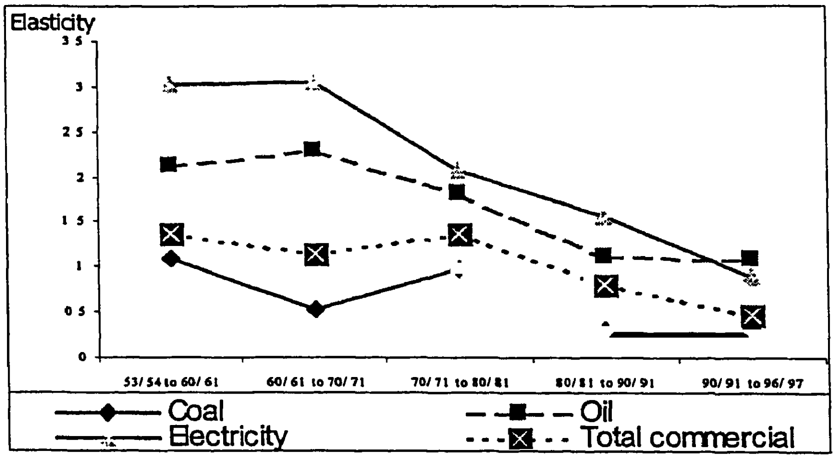
Regulators have also to be consistent. They must take care to see that their decisions stand the test of 'legitimate expectation' both in a procedural and substantive sense, and the concept of 'promissory estoppel'. After all, one of the objectives of regulatory reforms is to attract private investment. And private investment will be forthcoming only if the investors have confidence in the continuity of regulatory principles and tariff policies over time. The regulated utilities also need to know that regulatory approaches towards efficiency improvements and cost reduction are not one shot exercises, but would be continued over time.

The measures discussed above are some formal steps to ensure regulatory accountability but these alone are not enough. In the ultimate analysis, the regulators must realize that it is only by demonstrating to the stakeholders that their actions are consistent, always in the public interest, and are intended to promote developments of the sector, they can establish their legitimacy and credibility. Accountability, is therefore, not a procedural or accounting issue; it is a core issue in sound regulation.

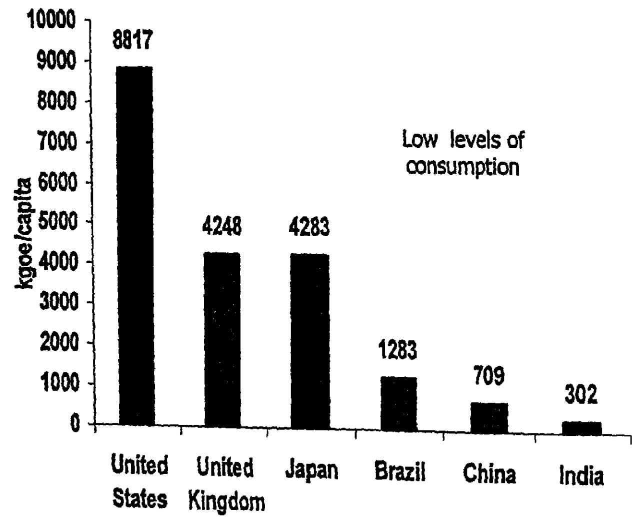
India's Energy Sector: an overview

P V Sridharan
TERI

Elasticity of final energy consumption with gross domestic product



Per capita energy consumption



Energy reserves

	Reserves		R/P ratio	
	India	World	India	World
Coal (bt)	70.0	1032	245	228
Crude oil (bt)	0.7	137	21	43
Natural gas (tcm)	0.7	139	38	65

Coal and lignite reserves (billion tonnes)

	Total	***Proven***
Coking coal	30	16
Non-coking coal	181	66
Total	**211**	**82**

Lignite:

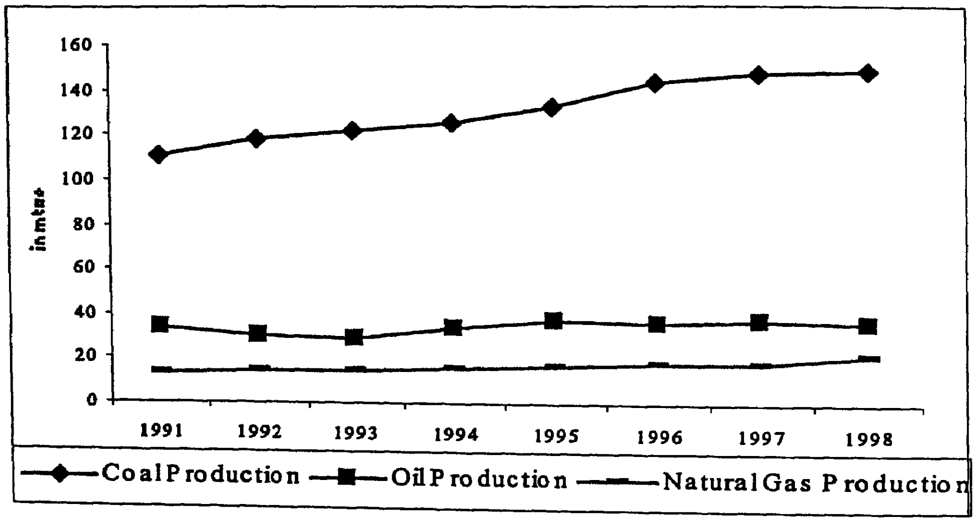
Tamil Nadu	26.7
Rajasthan	1.8
Gujarat	1.5
Total	**30.0**

Balance and recoverable reserves

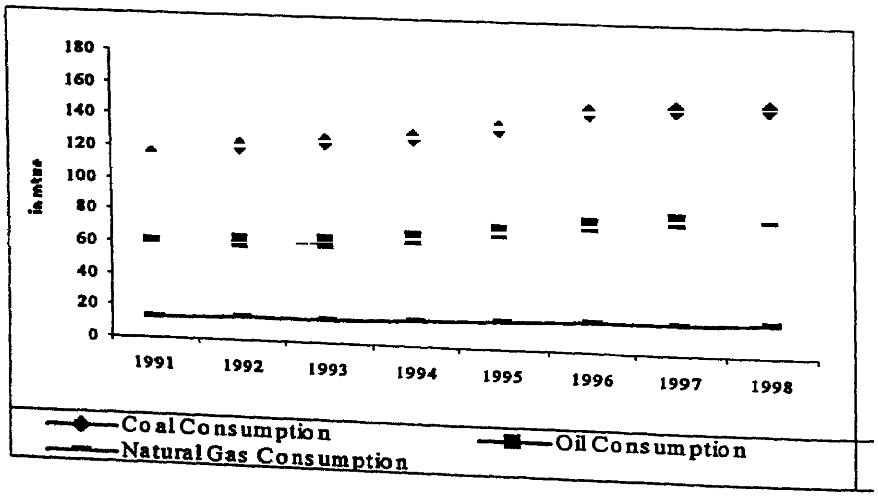
	1990			1999		
	Off shore	Onshore	Total	Off shore	Onshore	Total
Crude oil (MT)	432	307	739	352	308	660
Natural (BCM)	457	229	686	369	279	648

5

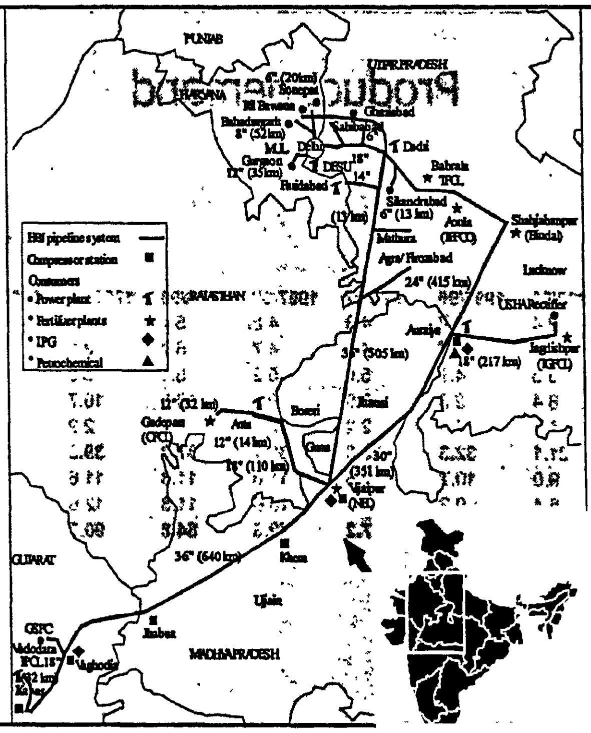
Trends in production of coal, oil, and natural gas



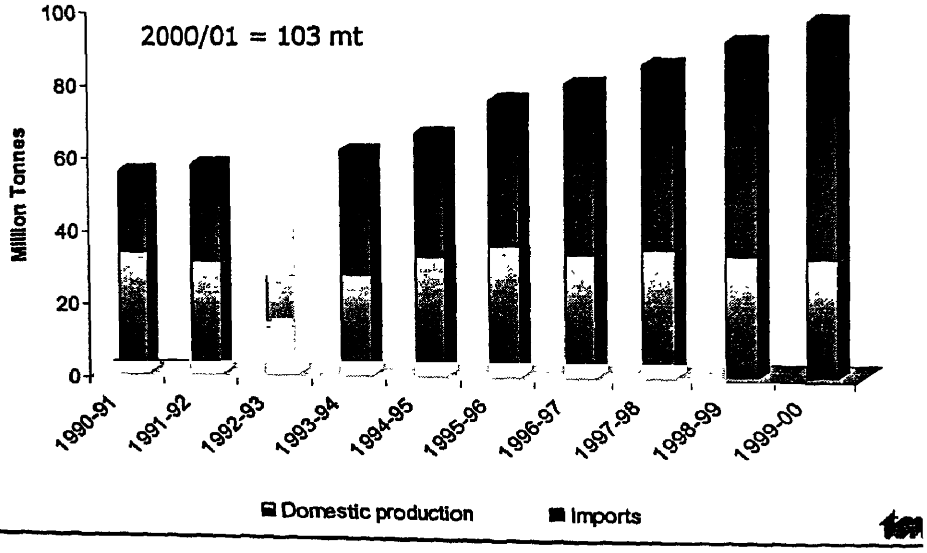
Trends in consumption of coal, oil and natural gas



Oil and Gas sector



Refinery throughput

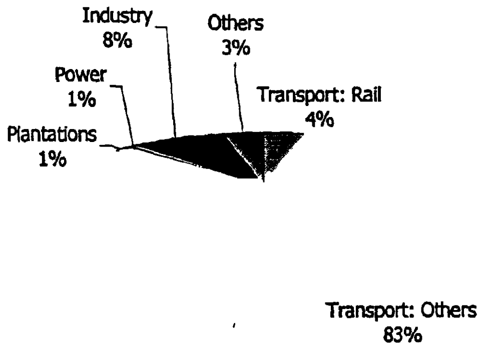


Product demand

Figures in MMT

Product	1990/91	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	CARG
LPG	2.4	3.8	4.3	4.8	5.4	6.0	6.6	10.6%
Naphtha	3.4	3.7	4.0	4.7	6.7	8.0	8.1	8.9%
MS	3.5	4.7	5.0	5.2	5.5	5.9	6.6	6.4%
SKO	8.4	9.3	9.6	9.9	10.6	10.7	10.7	2.4%
ATF	1.7	2.1	2.2	2.1	2.1	2.2	2.3	3.0%
HSD	21.1	32.3	35.0	36.1	37.2	39.3	38.2	6.1%
FO	9.0	10.7	10.8	11.0	11.3	11.6	11.3	2.3%
Others	5.4	9.2	8.3	10.6	11.8	12.6	6.5	1.8%
PSU sales	55.0	75.8	77.2	79.8	84.8	90.7	90.2	5.1%

HSD sectoral use:1998/99

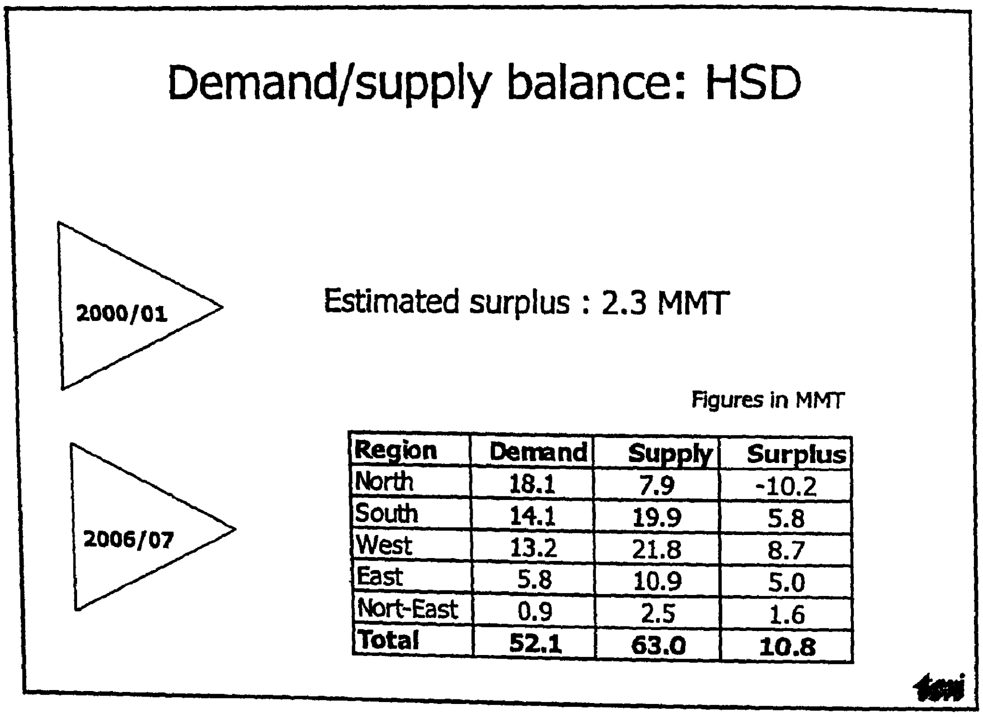


Regional demand: 2000/01

Figures in MMT

Region*	All Products	HSD
North	27.3	13.3
South	23.0	10.3
West	28.2	9.7
East	9.8	4.3
Nort-East	1.8	0.7
Total	**90.2**	**38.2**

** Pro-rated as per 1999/00 sales*



Demand/supply balance: HSD

2000/01

Estimated surplus : 2.3 MMT

2006/07

Figures in MMT

Region	Demand	Supply	Surplus
North	18.1	7.9	-10.2
South	14.1	19.9	5.8
West	13.2	21.8	8.7
East	5.8	10.9	5.0
Nort-East	0.9	2.5	1.6
Total	**52.1**	**63.0**	**10.8**

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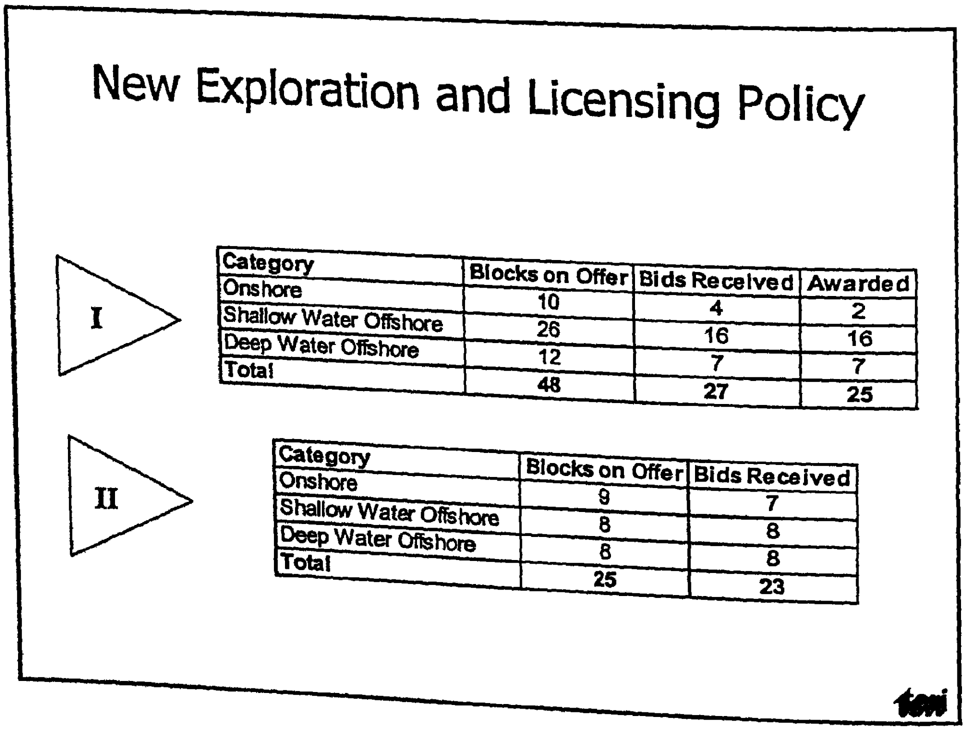

New Exploration and Licensing Policy

I

Category	Blocks on Offer	Bids Received	Awarded
Onshore	10	4	2
Shallow Water Offshore	26	16	16
Deep Water Offshore	12	7	7
Total	48	27	25

II

Category	Blocks on Offer	Bids Received
Onshore	9	7
Shallow Water Offshore	8	8
Deep Water Offshore	8	8
Total	25	23

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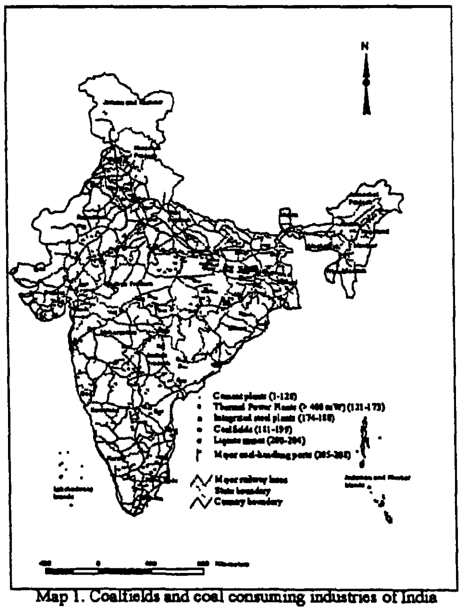
Coal sector


N
Cement plants (1-120)
Thermal Power Plants (> 400 mW) (121-173)
Integrated steel plants (174-180)
Coalfields (181-199)
Lignite mines (200-204)
Major coal-handling ports (205-208)
Major railway lines
State boundary
Country boundary
Andaman and Nicobar Islands
Kilometers

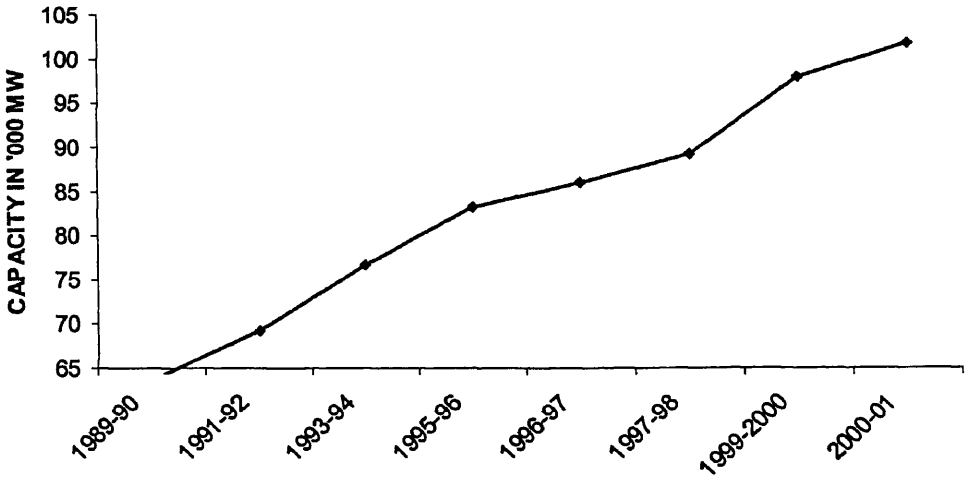
Map 1. Coalfields and coal consuming industries of India

Critical issues in coal sector

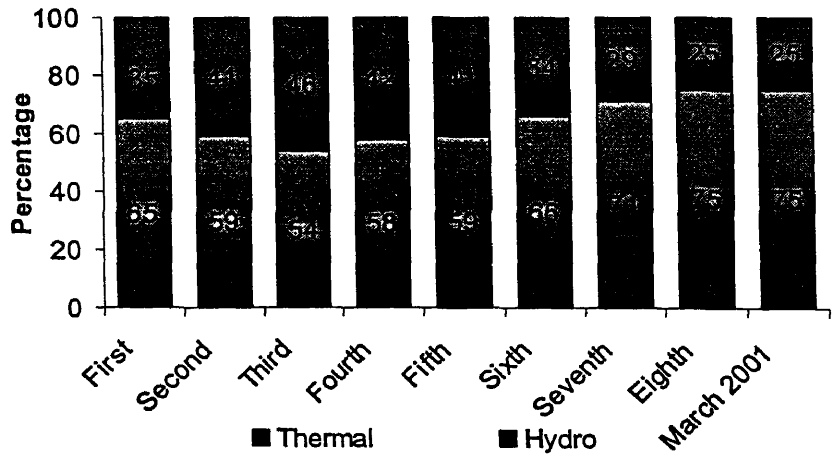
- Coal industry organizational issues
- Coal quality improvements
- Environmental and social aspects
- Efficiency improvement in operation
- Uneconomic mines
- Attract private investment
- Introduce competitive bidding for coal blocks
- Coal pricing, rail traffic and royalty

Power sector

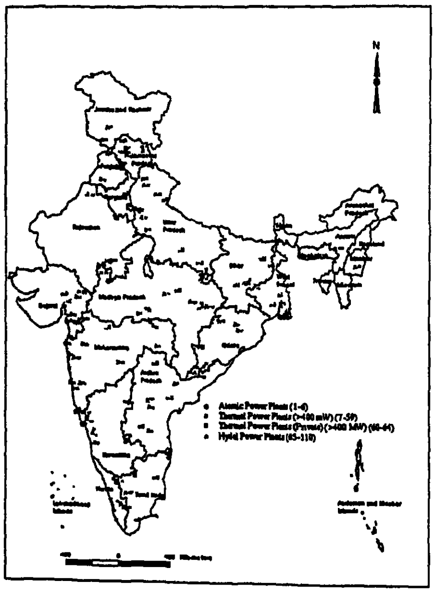
Growth in installed capacity - power generation



Imbalance in capacity

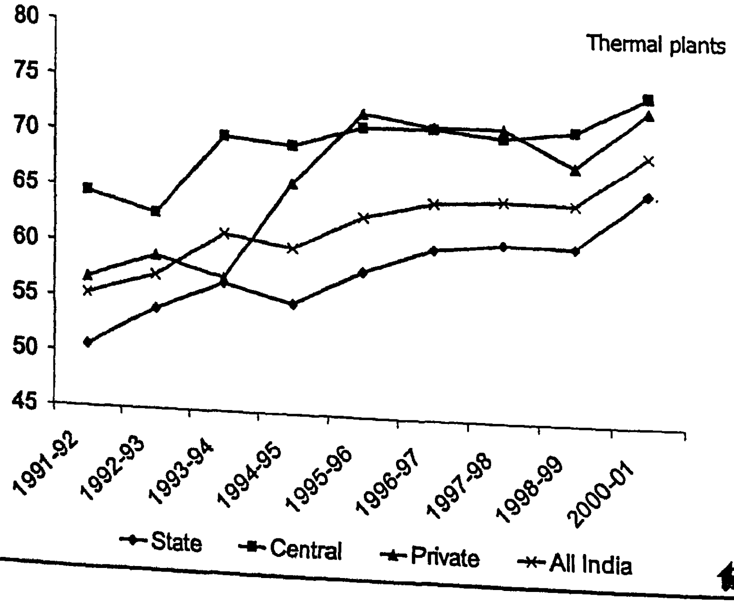


End of plan periods


N
Atomic Power Plants (1-6)
Thermal Power Plants (>400 mW) (7-59)
Thermal Power Plants (Private) (>400 MW) (60-64)
Hydel Power Plants (65-110)

Map 2: Major power generating units of India

Improvement in PLF



Shortage of electricity

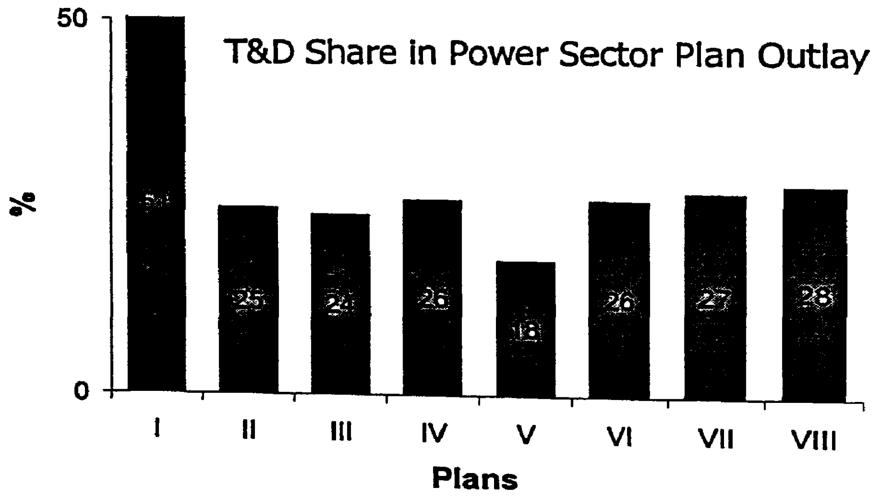
Region	**Energy**	**Peak**
	2000-01 (%)	
Northern Region	7.5	8.6
Western Region	10.7	19.1
Southern Region	7.9	14.4
Eastern Region	-0.1	3.1
North Eastern	-5.8	-1.6

Transmission and Distribution losses

U.P.	41.5%
Karnataka	38.0%
Andhra Pradesh	35.4%
Maharashtra	31.9%
Orissa	42.0%
Gujarat	34.3%

(Planning Commission)

Imbalance in investment



Effective subsidy and cross subsidization (Rs. Crores)

	1992-93	1999-00
1. Effective subsidy to domestic and agriculture sector	9370 (78%)	30786 (74%)
2. Cross subsidy from industrial and commercial sector	3911 (42%)	12434 (40%)
3. Losses for SEBs (without subsidy)	4560	13817

Critical issues in power sector

- Distribution privatization
  - Need to recognise lack of capacity
  - Unbundled privatisation (flexibility/innovation)
- Creation of competitive markets
  - Fuel supply
  - Bulk power
- Strengthening of regulatory commissions
  - Independence (Selection process, expertise)
  - Autonomy
  - Stability (policies)

Contd...

- Efficiency improvements
  - T&D losses
  - Quality of supply and service
- Tariff reform
  - Clear criteria for allocation of costs and estimation of efficiencies
  - Metering of agricultural supply

Electricity Bill 2000

- Consolidate and amend laws relating to supply and use of electricity
- Rationalize generation and supply
- Establishment of Regulation Commissions
- Rationalization of tariff
- Transparent policies on subsidies
- Promotion of efficient and environmentally benign policies

Electricity Conservation Bill 2001

- To promote and enforce progressive regime of energy conservation in the country
- Bureau of Energy Efficiency to be formulated (EMC will be merged with BEE)
- Provides for creation of energy conservation funds

Renewables: capacity and potential

	Existing (Mar '98)	Potential
Wind (MW)	969	20000
Small hydro (MW)	155.4	10000
Bagasse Cogen (MW)	82	3500
Biogas plants (million)	2.7	12

Energy sector characteristics

- Persistent shortages
  - demand > supply
- Poor internal rate of return
- Poor productivity/efficiency
- Limited energy alternatives for poor
- High import dependence - oil, BOP pressures
- Subsidies

Environmental concerns related to the energy sector

- Rehabilitation and resettlement
- Air quality
- Safety
- Fuel quality
- Waste disposal
- Ash disposal and management

Implications of urbanization on energy sector characteristics

- Increasing income and better lifestyles
- Increase in per capita energy use
- Greater dependence on electricity and petroleum products
- Increase in peak electricity demand
- Dependence on personal modes of transportation
- Heavy air pollution in urban centres

Ongoing action

- Deregulation
  - Oil & gas : Exploration (NELP), Refining & Marketing
  - Coal : Captive mining for power, mining
  - Electricity : Generation (IPP), Distribution & Transmission (?)
- Regional co-operation in energy
  - gas from Bangladesh
  - power from Pakistan, Bhutan, Nepal
- Promotion of renewable energy technologies

Present status of reforms ...

- Privatization of distribution only in Orissa
- SEBs restructured with separate entities in A.P., Orissa, Haryana, Karnataka, U.P.
- Regulatory Commission established in U.P., Haryana, Rajasthan, Gujarat, Madhya Pradesh, Maharashtra, Orissa, Andhra Pradesh, Karnataka, Tamilnadu, Delhi, Arunachal Pradesh, West Bengal.

Contd...

- Tariff orders issued in Orissa, Maharashtra, Andhra Pradesh, U.P., Karnataka, Haryana, Delhi and Gujarat
- Availability based tariff and Operating norms issued by CERC

Current developments

Poorly coordinated

- Uneven reforms programme
- Uncoordinated developments in coal and power sectors
- Inadequate attention to distributed generation
- Transport bottlenecks

Benefits of regulation

- Regulatory risk is perceived to be lower than political risk associated with Government
- Independent regulators can take tough decisions needed to improve financial health and depoliticise decision making
- Professional decision making can help to improve operational efficiency and customer satisfaction
- Greater transparency can mobilize public opinion in the right direction

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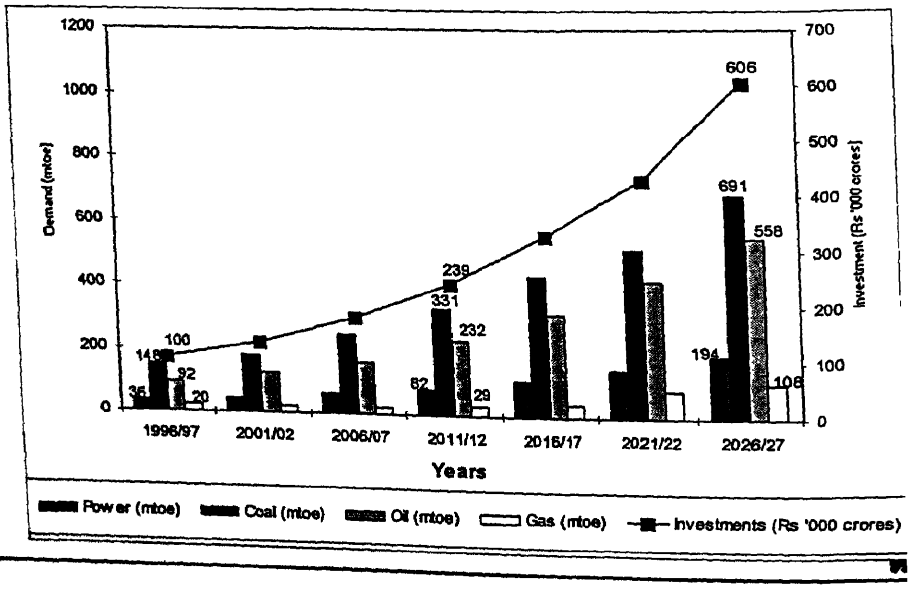
Limitations of regulation

- Problems in regulating public sector monopoly - lack of profit motive.
- Relationship with judiciary
- Inadequate capacity and experience in regulation of industry
- Dependence on Government for policy decision, staffing and funds.

Reforms and the environment

- Promotion of RETs
- Incentives to efficiency improvements
- Waste recycling / cogeneration
- Clean coal technologies
- Coal washing and fly-ash handling
- Dismantling of the APM / Re-structuring
- Decentralization of environmental clearances

Future energy scenarios



Future choice determinants
Energy availability

- Coal Resources: Physical and infrastructure constraints
- Oil: Proven reserves
- Gas: Access, infrastructure
- Renewable
  - Wind
  - Biomass
  - Solar

Future choice determinants
Environmental concerns

- Local Environmental issues
  - Fly Ash
  - Water
  - Social
  - Deforestation
- Regional: Acid Rain
- Global: Climate Change

Need for integrated energy policy

Arises from

- Need for effective utilization of scarce resources
- Substitution possibilities
- Interdependence of financial health
- Cost minimization including environmental effects

Power Sector

Reform of Electricity Distribution

Partha Mukhopadhyay
October 15, 2001

Why Reform?

- Unsustainability
  - Fiscal Unsustainability
    - State Governments cannot bear the burden of SEB losses
  - Political Unsustainability
    - How long will the people be willing to put up with poor quality electricity supply?
- Necessity for Economic Growth
  - India's Cost of electricity for industries is about 3 times that of China
    - It doesn't have to be

What is Reform?–Orissa Style

THE ORISSA MODEL	
Unbundle G, T and D	
Major System Investments before Privatisation	
Single Government-Owned Buyer	
Annual Regulatory Approach	
Transfer limited to Asset related liabilities	
Privatisation of Mixed Zones	

Key Learnings...

- **Focus was on Unbundling and Privatisation**
  - **Necessary but not Sufficient for sector reform**
- **A More Comprehensive Approach is Required**
  - **Reform is not an event, like privatisation but a process**
- **Need to Address the “Two Deficits”**
  - **Past Burden**
  - **Future Requirements**

The Two Deficits

- **Past Burden**
  - **Unpaid dues to suppliers**
    - **Mostly to Central Units like CIL and NTPC**
  - **Unserviceable Loans**
    - **Mostly to PFC, REC and lately to FIs and Banks**
  - **"Unfunded" Liabilities**
    - **Employee pensions and State Government Loans**
  - **Unfunded Contingent Liabilities**
    - **Escrows and Long-term PPAs**
  - **Uncertain Assets**
    - **Doubtful Receivables, e.g., State Govt. Subsidy**
- **Future Requirements**
  - **Operating Losses during Transition**
    - **Related to Regulatory approach and efficiency**
  - **Investments in System Improvement**
    - **Essential to Ensure that these are "efficient"**

Estimates of The Two Deficits

Estimates of Deficit during 2000-04 (Rs. Crore)

Sources: The World Bank, Ministry of Power

Item	Andhra Pradesh	Rajasthan	Uttar Pradesh	Total	%
Cash Operating Deficit	678	-1163	3584	3099	6
Increase in Working Capital	1175	454	-793	836	2
Service of Past Debt	8557	7188	4083	19828	38
Service of Future Debt	3746	352	3057	7155	14
Capex	8426	7109	5377	20912	40
Total Deficit	22582	13940	15308	51830	
Total Outstanding Dues (Feb. '01)	1468	808	5482	7758	

Approach

Address the Past and Contain the Future

Deficit	Address the Past	Contain the Future
Loans, Subsidies, Receivables	Takeover by Government	
Unfunded Pensions	Takeover by Government	Funded Pensions
Unsustainable Escrows & PPAs	Work-out by Government	Direct Contracting by Private DISCOMs
Poorly-maintained Distribution Network	Accept that Assets have low value	Efficient Private Investment
Operational Losses		Limit losses through Private Participation & Regulatory Stability

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What is Reform?–Alternative Approach

THE ORISSA MODEL	SUGGESTED APPROACH
Unbundle G, T and D	Unbundle G, T and D
Major System Investments before Privatisation	Major System Investments **after** Privatisation
Single Government-Owned Buyer	**Direct Contracting** with Generators
Annual Regulatory Approach	**Multi-Year** Regulatory Approach
Only Asset related liabilities transferred to DISCOMs	Only ***"certain"*** related liabilities transferred to DISCOMs
Privatisation of Mixed Zones	Privatisation starting with **Concentrated Urban Zones**

Six Steps to Accelerated Privatisation of Distribution

---

1 Do not Add to Burdens

- Avoid Escrows and Long-term PPAs

- They reduce attractiveness of distribution business
  - Distribution company does not have first charge on its own cash flows
    - e.g., Central Zone in Orissa
- Deleterious effect on competition
  - Prevent distribution companies from accessing more competitive suppliers of energy
- They are inequitable
  - New distribution companies are not party to these agreements in the first place

Six Steps to Distribution Privatisation...

2 Spell Out Market Structure

- Vest* existing generators to DISCOMs
  - Can replicate existing average cost of supply without a single buyer approach
    - Similar to ABT, which is already familiar, courtesy CERC and NTPC
  - Can also be used for "burden-sharing"
- Direct commercial transactions
  - Private DISCOMs buy directly from generators
  - Large buyers can access generators directly
    - An access surcharge can be levied
- DISCOMs contract directly with new suppliers for their incremental needs

---

Six Steps to Distribution Privatisation...

3 Ensure Stable Regulatory Regime...

- Medium-term tariff orders
  - Instills confidence in private investors prior to privatisation
  - Reduces uncertainty related to tariffs and performance expectations
- Realistic Tariff orders
  - Based on easily verifiable numbers
  - Reasonable targets for loss reduction
  - Adequate provision for investment

Six Steps to Distribution Privatisation...

4 Retain Liabilities with Government

- Can mean more money from Sale
  - Asset valuation: 400
  - Expected Liability : -100 with prob. ½ ; -300 with prob. ½
  - Actual Risk Averse Bid: Less than 200
  - 'True' liability = 150 i.e., 'True' value = 250 (realised ex-post)
- Plough-back proceeds to PSRF
  - Include sale of generation assets in future

Six Steps to Distribution Privatisation...

5 Separate Urban and Non-Urban Zones

- Quicker privatisation and Better valuation
  - Eliminates the time and effort involved in achieving a "balanced" configuration of distribution zones
  - Isolation of subsidy-related uncertainty
- Accelerated loss reduction
  - Majority of T&D losses seem to be in urban areas
- Positive impact on subsidy bill
  - Removes scope for camouflaging urban theft under Agricultural consumption

Six Steps to Distribution Privatisation...

6 Auction Urban & Non-Urban zones

- Urban Zones
  - Sale of Equity / Concession Fee
  - Avoid Multi-parameter bids
- Rural Zones
  - Private Sector is not a full "commercial" player in Rural Electricity Distribution anywhere
    - Minimum subsidy bidding
  - Encourage decentralised generation options
    - e.g., biomass, micro-turbines, etc.

Just Do It !

Six Steps to Distribution Privatisation

Steps and Sub-activities	1	2	3	4	5	6	7	8	9	10	11	12
1. Policy Preparation (1 month)												
2. Financial Restructuring (6 months)												
3. Distribution Zoning (3rd month) [16]			◆									
4. Stable Regulatory Regime												
4a. Preparing the Tariff Submission (4 months)												
4b. Medium Term Tariff Submission (7th month) [16]							◆					
4c. Tariff Examination by SERC (3 months)												
4d. Medium Term Tariff Order (10th month) [16]										◆		
5. Market Structure – Decision on Open Access						◆						
6. Sale of Distribution Business												
6a. EOI (1st month) [16]	◆											
6b. Issue of RFQ (3rd month) [16]			◆									
6c. Submission of RFQ (5th month) [16]					◆							
6d. Evaluation of RFQ (2 months)												
6e. Issue of RFP (7th month) [16]							◆					
6f. Due Diligence by bidders (4 months)												
6g. Final Bid Preparation (1 month) [16]												
6h. Auctions (1 month)												

Interim Steps by SEB

- **"No-investment" Improvements**
  - **Big impact on consumer but small impact on budget**
- **Data improvement**
  - **Cash Collections**
  - **Energy Audit**
  - **Receivables**
  - **Identification of Contingent Liabilities**
- **Labour Rationalisation**
  - **Reduce desk staff and increase field staff**
    - **Overall staff strength to reduce by attrition**
  - **VRS financed out of PSRF and Multilateral loans**

Questions?

SEB Performance (2000-01)

- Rate of Return (without subsidy) : (-) 35.1%
- Commercial Losses (without subsidy) : Rs. 26,013 crore
- Gross Subsidy : Rs. 37,037 crore
- T & D Losses : 23% (Reported)
  - Reality : anywhere between 40 to 60 %
- Outstanding Dues to Central Units (as on Feb'01) : Rs. 41,473 crore
- Revenue Arrears (1998-99) : Rs. 18,786 crore

Zoning and Market Structure

- Formation of distribution zones by combining urban and rural loads
  - Scope for disputing efficiencies
  - Privatisation
- Single Buyer Model
  - Rationale for 'pooling' low-cost and high-cost power
    - To ensure uniform price across regions and facilitate honouring of PPAs
  - But...
    - Restricts Competition
    - Retains bankrupt state-owned transmission company in the picture
    - Opens scope for perpetuating long term PPAs

Annual Cost-plus Tariffs

- **Bidding in the dark, with regard to regulatory approach and parameters**
  - **Reduces the number of potential bidders**
- **Diminishes incentives for aggressively pursuing efficiency**

- **Problems in regulating government-owned utility**
  - **How to deal with mounting losses? e.g. Regulatory Assets**
  - **What if the commercial payment discipline is vitiated? e.g. Orissa**

Financial Restructuring

- **Financial Restructuring to create a positive capital base for the new entities,**
  - **Asset Valuation, Apportionment of assets and liabilities, Setting off SEB dues, etc.**
    - **Overvaluation of assets lead to higher tariff for consumers**
- **Major investments prior to privatisation**
  - **The private sector perspective is that the "Liabilities-side is a reality while the asset-side is a belief"**

Mechanism for Capital Restructuring

Loans due to the State Government	Written off
Subsidy due from State Govt.	Written off
Overdues to Suppliers	Rescheduled (Liability of State Govt.)
Pensions, Gratuity etc. to Employees	Liability of the PSRF
Future Subsidy due from State Govt.	Liability of the PSRF
Receivables	Asset of the PSRF
Structural Adjustment Loan	Paid into the PSRF (Liability of State Govt.)

What is PSRF?

Power Sector Reform Fund (PSRF)

- **A Mechanism to:**
  - **Ring-fence Revenues from privatisation for use within the sector**
  - **Make the cost of restructuring the power sector transparent**
- **All Existing Uncertain Assets and Liabilities to be put into PSRF**
  - **Existing Receivables become PSRF assets**
    - **Exception: Loans for identified assets which are transferred to DISCOMs**
  - **All Sale proceeds credited to PSRF**
    - **Overflow to State budget after meeting Liability**

Six Steps to Distribution Privatisation...

2 Avoid Single Buyer Model because...

- Linkage between consumer and supplier is weak
- Weakens incentives for distribution companies to collect payments
- Creates contingent liability on government
- Gives wrong market signals
  - demand shortfall triggers price increases!
- Hampers development of electricity trading

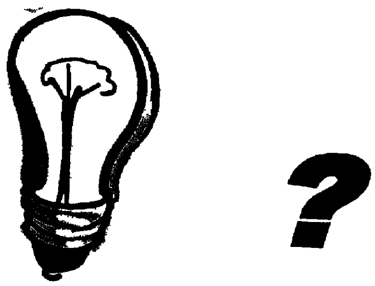
Six Steps to Distribution Privatisation...

3 ...Avoid Inappropriate Regulation: Kesco

- Medium Term Loss profile given but...
  - Expected Performance levels indicated in tariff order appear near impossible
    - Collection efficiency to go to 100% immediately
    - Losses to drop by 5 % in first year
- Unequal sharing of benefits in Tariff Order
  - Rs. 120 crore increase in income for UPPCL from bulk tariff sales
  - Rs. 12 crore return, with a host of risks, for the potential private investor
- Need for more transparent and equitable allocation of risks for expediting privatisation

Sample Vesting Contract

- **N-Zone**
  - Nagpur (77%) and Nagpur Urban (23%) Zones
  - 5.5% Agricultural load
    - 2600 MU (350 MW) of base and 460 MU (115 MW) of non-base
- **Financial Vested Contracts**
  - Fixed capacity charge and actual fuel cost for (say) 5 years
    - 250 MW from Khaparkheda and 100 MW from Parli
    - 100 MW from Uran (45% PLF)
      - N-Zone pays capacity charge in proportion
    - Varasgaon and Bhatsa hydro stations (~70MU)
- **N-Zone** purchases for incremental growth
  - Can sell surplus if metering reduces consumption



Settlement of SEB Dues Owed to CPSUs

Settlement of SEB dues owed to CPSUs

Over the years SEBs have been defaulting in their payments to the CPSUs of the Ministry of Power, Department of Coal, Atomic Energy, Railways, BHEL etc. The outstanding dues payable to the CPSUs of Ministry of Power alone were Rs. 30,000 crores as on 28.2.2001 (Principal Rs. 18,100 crores and surcharge aRs. 11,900 crores).

2. From time to time Govt. of India has resorted to appropriations from the Central Plan Assistance (CPA) of the concerned States to recover the outstandings of the Power Sector PSUs. Between May, 1990 and March, 1994 three such recoveries were made from the CPA of the defaulting States. In February, 1997 Govt. again approved the recovery of outstanding dues of the CPSUs as on 31.12.1996. However, this time the recovery was restricted to 15% of the CPA and besides the outstandings of the CPSUs of Ministry of Power, the CPSUs of Deptt. of Coal, Atomic Energy, Railways and BHEL were also included.

3. Recognising the problem of mounting arrears, the Finance Minister in his Budget speech for 1998-99 announced that Government would evolve a scheme for securitising the dues of the SEBs to the CPSUs of the Ministry of Power and Deptt. of Coal so that funds could be made available for the investment needs of these sectors. Subsequently in July, 2000 Government approved a scheme for securitsation of the SEB dues. The main features of the scheme were as under:-

a) The defaulting SEBs would issue bonds to the CPSUs of the Ministry of Power and the Deptt. of Coal to cover the principal amount due upto 31.12.1999 or any other mutually accepted date.

b) The bonds would be backed by a State Government guarantee with specific allocations made in the State Government's Budget for servicing the bonds in the event of the SEBs being unable to do so.

c) By way of further comfort to the bond holder, the Central Government would undertake to use the existing authorization to deduct upto 15% of CPA allocations of the State concerned for the purpose of redemption of bonds if the State Government is unable to meet the guarantee obligation.

d) The bonds would have tax-free status.

4. With the above features, the bonds were expected to be tradable in the secondary market and the Central PSUs would have the option to recover their money by selling the bonds in the secondary market.

5. The facility of issue of guaranteed tax free bonds by the SEBs was to be extended only to those SEBs/State Governments who agreed to implement a suitable reform

package including payment of current dues by the SEB; opening of LC to the extent of 105% of the current dues; adhering to milestones of reforms formulated by the Ministry of Power such as setting up of the SERC, filing of tariff petitions, reduction in T&D losses, 100% metering etc.

6. The response of the States to this scheme was at best lukewarm. Only the state of West Bengal reacted positively to the proposal with a condition, however, for a full waiver of surcharge. An attempt was made to salvage the scheme with a view to generate additional cashflow for the CPSUs without requiring any sacrifices from the States. A meeting of the Power Secretaries of States was convened in September, 2000 wherein a possible alternative mechanism was discussed. The consensus was in favour of setting up a Special Purpose Vehicle (SPV) to issue the tax free bonds. In other words, the SPV would securitise the cash receipts from the 15% CPA deductions of the States which have outstandings. However, when the matter was examined in detail, it was felt that the onus of servicing the debt under this scheme would then shift from the States to the Centre. The 15% CPA deduction was meant to be a back up of last resort only; otherwise it is for the SEBs/States to own their liabilities and take effective measures to meet them. The proposal could not, therefore, be proceeded with.

7. The Chief Ministers' Conference held in March 2001 presided over by the Prime Minister discussed the state of the power sector and emphasized the urgency of reforms as a necessary pre-requisite for ensuring rapid growth of the economy and preserving the health of State finances. The Conference noted that the large amount of dues owed by the SEBs to the CPSUs was a major impediment to reforms and resolved to constitute an Expert Group to recommend (a) a one-time settlement of outstanding dues, and (b) recommend a programme for medium-term capital restructuring and reform of the SEBs. An Expert Group under Dr. M.S. Ahluwalia, the then Member (Energy), Planning Commission was constituted in pursuance thereof.

8. The Expert Group submitted its report on one-time settlement of SEB dues in May 2001. The Group noted that the dues of the SEBs had accumulated to Rs. 41,473 crore consisting of Rs. 25,727 crore of principal and Rs. 15,746 crore of interest/surcharge. The Group felt that these dues have arisen not because of some exceptional event, or of problems that arose in the past which are no longer operative, but because of the continuing non-viability of the current operations of the SEBs. A settlement of past dues alone would not solve the basic problem facing the SEBs; and unless the problem of current unviability is speedily addressed, overdues would mount again.

9. The Group, therefore, suggested a scheme for settlement of outstanding dues, linked to a mechanism that would ensure payment of current dues in future. The Group's recommendations included a package of incentives and disincentives linked to commercial discipline and initiation of a process of reforms. The Report acknowledged that the recommendations did not amount to a full-fledged programme of reform and restructuring which is a complex matter. However, they did establish a linkage between the settlement of dues and the start of a reform process.

The main features of the scheme recommended by the Group are as follows:

- For the States participating in the scheme, 50 per cent of the surcharge/interest on delayed payments shall be waived. The rest of the dues amounting to the full principal amount as well as the remaining 50 per cent of the interest/surcharge, aggregating Rs. 33,600 crore should be securitised through bonds issued by the respective State Governments. If the additions arising out of conversion of old bonds, as well as incentives for better managed SEBs, to be partly offset by reductions resulting from settlement of disputes are taken into account, the total securitisation under this scheme may be about Rs. 35,000 crore.
- The bonds shall be issued through the RBI at a tax-free interest rate of 8.5 per cent per annum. The bonds shall carry a moratorium of 5 years on repayment of principal with the entire principal being repaid between the 6th and 15th year. These would be identical to the market borrowings of State Governments, with the attendant discipline in repayments. The bonds would be subject to lock-in restrictions that will allow release of only 10 per cent of the bonds in the secondary market each year.
- For ensuring timely payment of current dues in future, defaults in current payments for power/fuel shall attract a graded reduction in the supply of power from central power stations and in coal supplies. Where such defaults exceed 90 days from the date of billing, the Ministry of Finance should recover these dues through adjustment against releases due to them from the Centre.
- In order to initiate steps towards reforms of the sector, SEBs would accept reform-based performance milestones such as setting up of SERCs, metering of distribution feeders and improvement in revenue realization. The milestones would be specified in the MOUs to be signed with the Ministry of Power.
- The States shall be offered incentives for complying with the scheme. If SEBs do not default on their current dues and adhere to the performance milestones, CPSUs shall pay them, during the first four years commencing from 1.4.2001, bi-annual cash incentives equal to 2 per cent of the value of bonds. Further, if SEBs open and maintain LCs till the end of December 2001, CPSUs shall pay them a one-time cash incentive equal to 2 percent of the value of bonds. These incentives could add upto Rs. 6,300 crore. In addition, States undertaking reforms shall also be assisted through grants from the Accelarated Power Development Programme and discretionary allocation of power.
- The scheme will enter into force only after one-half of the States that have an annual billing of over Rs. 500 crore per annum from CPSUs give their consent, and would be effective in respect of the States that give such consent.
- The States that do not consent even after 60 days of the entering into force of the scheme shall be denied any share in the discretionary allocation of

15 per cent from the power stations of CPSUs as well as any assistance under APDP. If the overdues of such States exceed Rs. 50 crore in respect of any CPSU, they shall also attract reduction in power and coal supplies, as applicable to the States participating in the scheme.

11. The Group pointed out that the scheme proposed has carefully balanced the interests of all Stake holders, and modifications aimed at reducing the burden on one of the stakeholders will only increase the burden on others. The Group cautioned against relaxation in the various disciplines prescribed in the scheme as this would seriously comprise the integrity of the scheme.

12. The recommendations of the Expert Group were considered by the High Level Empowered Group of Chief Ministers constitited for reviewing the power sector reforms. The following suggestions were made on behalf of the States:-

i) The entire surcharge should be waived and the securitisation limited to the principal outstandings only.
ii) The bonds should carry a moratorium of 5 years for both principal as well as interest.
iii) Even after the settlement, some of the States would be unable to meet their current expenditure from the revenues till a complete turn around is achieved. Part of the current dues may, therefore, be deferred or collected by way of bonds.
iv) Instead of State Governments issuing the bonds, the SEBs may be allowed to issue the bond backed by a State Government guarantee.
v) The return on equity @ 16% applied to investments already made on the date of notification should be withdrawn. Similarly, increased depreciation norms should not be made applicable to assets already commissioned. Income tax payable by SEBs should not be allowed to be a pass through in the tariff.
vi) Wherever CPSUs owe money to the States, the outstandings should be set off against the SEBs' dues towards CPSUs. For this purpose no differentiation should be made whether the defaulting CPSU belongs to the Ministry of Power or any other Ministry.
vii) The outstandings payable to the Rural Electrification Corporation (REC) should be also settled but, in more favourable terms for the SEBs as the investments have been made on non-renumerative assets.
viii) CERC orders on tariff must be complied with.
ix) Coal prices have been increased indiscriminately in the recent past. The issues relating to coal supply including the pricing of coal should be referred to an independent regulatory authority to be set up by the Department of Coal.

13. The Empowered Group of Chief Ministers after detailed discussions decided to accept the recommendations of the Expert Group with the following modifications:-

i) Waiver of surcharge may be increased from 50% to 60%.
ii) The incentive payable by the CPSUs for achieving performance milestones may be increased to 6% of the total value of the bonds in the first year and 5% in the second year.
iii) A separate Expert Group may be constituted to consider the dues payable to REC.
iv) The Ministry of Coal shall explore the possibility of setting up of a regulatory authority for coal.

14. The State Governments are presently in the process of finalizing their tripartite agreement with the CPSUs and the Reserve Bank of India after which the scheme of one-time settlement will be operationalised.

The following paper was presented at:

National Conference on Transition to a Liberalized Environment: Experience and Issues in Regulation

Date: 3 – 4 February 1999

Tata Energy Research Institute,
New Delhi

Background paper on Power

K Ramanathan, Senior Fellow, TERI, New Delhi
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The electricity industry forms a critical part of India's infrastructure and its continued expansion is necessary to ensure rapid economic growth and the overall success of the liberalization efforts. Recognizing the importance and the need to ensure that sufficient resources are available to meet the rapidly growing demand, the government, since 1991, has initiated a series of policy reforms. The main objectives of the reform process have been to improve the performance of the industry, to correct distortions existing in the tariff structure, to ensure dynamic and sustainable growth of the electricity industry in India and to encourage and facilitate participation of private capital, wherever necessary.

Traditionally, the electricity industry in India has been regulated as well as owned by various government agencies and organizations. The role and participation of the private sector was limited and confined to specific areas of small jurisdiction and consumer base. The government, through the authority conferred by different legislations, took upon itself the role of thedeveloper, promoter, and the regulator of electricity.

The subject electricity is covered under the Concurrent List in the Constitution of India, implying that both the Central government and the state governments have the power to legislate the sector. A number of organizations and departments perform specific tasks in aiding the development of the sector. These include the Ministry of Power, Government of India; Central Electricity Authority, The National Thermal Power Corporation (NTPC), National Hydro Power Corporation (NHPC), the Power Grid Corporation of India Limited (PGCIL), the Power Finance Corporation (PFC), the Rural Electrification Corporation (REC), state electricity boards (SEBs), etc.

The total installed capacity, as on 31 October, 1998 was approximately 90 000 MW with the share of hydropower being approximately 25%. In spite of significant capacity additions during the five decades following independence, various parts of the country continue to experience shortages of energy as well as peak power. During the year 1997/98, the energy shortage was of the order of 8.0% while the peak shortage was approximately 11.0%. The operational performance of the sector has been characterized by low plant load factor and high transmission and distribution losses. Lack of financial resources and a desire to improve the performance of the industry have been the key drivers of the reform programme.

The sector has witnessed significant and rapid changes during the past few years. These involve new policies for inviting private participation in the sector, setting up of independent and autonomous regulatory authorities, and increasing recognition of the need to operate the organizations in the sector on commercial principles. The need for reorganization was felt in view of the rapidly increasing demand to improve the functional performance of the industry and due to resource constraint faced by the public sector enterprises (PSE), particularly by the SEBs to invest in new projects. The main cause for lack of financial resources has been the lack of political will to increase the tariff to realistic levels. The subsidy and the cross-subsidies in the sector have led to a distorted consumption pattern and rapid growth of captive power plants. The essence of the reorganization has been to ensure financial viability of the organisations in the sector, to provide better value to the customer to attract private capital into the sector.

Reforms were initiated by the central government in 1991, when it introduced the policy to liberalize the sector and promote private investments in the sector. This policy focussed initially on the generation side of the business. Its main objective was to add generation capacity in a short time-frame through private capital by making the sector attractive for investments. Since then, a series of further measures have been initiated by the government to expand and refine the policy for the sector. Amendments were introduced in the Indian Electricity Act and the Electricity Supply Act to facilitate the process.

Developments in legislations on regulation

Central sector

The Indian Electricity Act, the Electricity Supply Act and the Indian Electricity Rules provide the basic framework for regulation of electricity industry in India. These are discussed in brief in Appendix-1. These have been amended from time to time to reflect the policy changes and to make them suitable to the changing environment.

In 1996, the central government, along with the state governments, decided on a plan called the Common Minimum National Action Plan. The objectives of the plan were to initiate steps required to improve the performance of the sector at the central and state level in a time-bound manner. Setting up of the Central Electricity Regulatory Commission (CERC) and State Electricity Regulatory Commission (SERC) was a key element of this plan.

The central government passed the legislation enabling the setting up of independent and autonomous regulatory bodies at the central as well as the state level in July 1998. This is a significant step forward towards restructuring the electricity industry in India and is expected to provide an environment conducive to dynamic growth of the industry. The regulatory bodies are expected to promote competition, efficiency, and economy in consumption of electricity and in investments for the development of the sector.

This Act provides for the establishment of the CERC to regulate the tariff of the central generating companies; andother generating companies in case of a composite scheme for generation and sale of electricity to two or more states and to regulate the inter-state transmission of electricity undertaken by the Power Grid Corporation of India Limited and other organizations including the tariff payable to them.

The Act also makes avenues for the establishment of a State Commission as an option (not as a mandate) to the State Governments. The state government can establish such a State Commission in terms of the Act for the purposes of determining the tariff/charges payable for the intra-state transmission and supply of electricity in the state. The State Commission will also regulate the working of the licensees and others involved in the electricity industry in the state.

The functions of the CERC include the following.

- To regulate the tariff of generating companies owned or controlled by the central government.
- To regulate the tariff of generating companies other than those owned or controlled by the central government specified in clause (a), if such generating companies enter into or otherwise have a composite scheme for generation and sale of electricity in more than one state
- To regulate the inter-state transmission of energy including tariff of the transmission utilities
- To promote competition, efficiency, and economy in the activities of the electricity industry
- To aid and advise the central government in the formulation of tariff policy which shall be--
  - fair to the consumers;
  - facilitate mobilization of adequate resources for the power sector;
  - to associate with the environmental regulatory agencies to develop appropriate policies and procedures for environmental regulation of the power sector;
  - to frame guidelines in matters relating to electricity tariff;
  - to arbitrate or adjudicate upon disputes involving generating companies or transmission utilities in regard to matters connected with clause (a) to (c) above; and
  - to aid and advise the central government on any other matter referred to the Central Commission by that government.

The enactment of the Regulatory Commissions Bill and establishment of the CERC is a positive step in the right direction. There are, however, a number of other measures, especially at the state level, which need to be initiated urgently to provide a comprehensive solution for restructuring of the power sector. The Regulatory Commissions bill has facilitated the setting up of State Regulatory Commissions and many states have indicated their willingness to set up the same. The states, however, also need to consider the option of enacting a reform bill to facilitate comprehensive reform, i.e., restructuring, unbundling, and corporatization of the vertically integrated SEB and related aspects.

The other important issue relates to phasing out of subsidy and cross-subsidy existing in the tariff structure of most of the SEBs. Clearly, this process would not be easy and will have to be graduated over a period of time. It would also require strong political will and commitment to the process of reforms.

State sector

A number of states have, in the recent months, indicated their willingness to reform the power sector and to set up regulatory bodies. The main driving force to establish independent regulatory commissions is the need to rationalize consumer tariffs. The issue of rationalization of tariffs is linked to the inability of SEBs to pay for IPP power. In such an environment many states found that IPPs were simply not willing to invest, as the projects seemed unviable.

Orissa

The State of Orissa was the first to initiate power sector reforms in the country when it enacted the Orissa Electricity Reform Act in 1995. Significant progress has been achieved since then and the Orissa example has now become a precedent which many other States are following or are likely to follow. The Orissa State Electricity Board (OSEB) was dissolved and unbundled as part of the reform programme. The generation business has been hived off into two corporations, i.e., the Orissa Power Generation Corporation (OPGC) which took over the thermal plants of the erstwhile OSEB and the Orissa Hydro Power Corporation which took over the hydro plants. The transmission and the distribution businesses were entrusted to the Grid Corporation of Orissa Limited (GRIDCO), which is the successor organization of the OSEB. The distribution business has been divided into four zones and is to be privatized by the end of financial year 1998/99.

Further, the Orissa Electricity Regulatory Commission (OERC) was established in 1996 as a part of the reform process. The powers and functions of the regulatory commission includes issue of licenses, enforcement of licenses and regulation of licensees, promotion of economic efficiency and safety in transmission, distribution and use, regulation of bulk supply and retail supply tariffs, collection of data and forecasting, and promotion of competition.

The commission, since its inception, has issued licences for transmission and bulk supply, distribution and retail supply, regulations for conduct of its proceedings and discharge of its functions. It has issued two tariff orders and its last tariff order was issued on 21 November , 1998 for bulk supply and transmission tariff and retail supply and distribution tariff separately. It has issued orders giving consent to setting up of captive power plants and for third party sale. The commission's future course of action envisages approval of the grid and distribution code and formulating consumer grievance redressal machinery for the licensee's. It is also working towards developing a regulatory MIS, issue of consumer rights' statement, power system planning and security standards, operating standards and holding of inquiry proceedings on supply position at selected areas.

Orissa has followed the UK model in terms of unbundling of the generation, transmission, and distribution business. The approach has been to privatize the successor distribution and generation business at the earliest while the transmission business is to be privatized at a later stage. A number of states are likely to follow this model with Haryana and A P having already enacted legislation on a similar pattern

Haryana

The Haryana Electricity Reform Act was passed in 1998 and the Haryana Electricity Regulatory Commission was enacted according to the provisions contained therein on 17 August,1998. At the same time, the Haryana Electricity Board has been unbundled and the generation, transmission. and distribution businesses have been corporatized under separate activities. Two distribution zones have been formed and at the first stage, it is proposed that east zone would be privatized with the government of Haryana retaining equity participation. An information dissemination programme has been launched relating to restructuring and reform activities.

Haryana has followed the Orissa model with secondary changes. The privatization of the distribution business at the first stage is limited to one of the two zones. This will provide an opportunity for comparison of performance of a private operator with the state owned utility. The programme is expected to proceed at a rapid pace as compared to Orissa and hence will provide useful comparison with performance in Orissa. Further, the socio-political environment in the state is significantly different from Orissa and successful implementation would not be easy and would require strong political will and adroit manoeuvering skills

Gujarat

The Government of Gujarat had initiated the reform programme in 1997. The principal components of the programme involved setting up of an independent regulatory commission to restructure the Gujarat Electricity Board (GEB), modernize and upgrade the distribution system, and clear the backlog of connections for agriculture sector. The state government has notified the constitution of the Gujarat State Electricity Regulatory Commission in November 1998 and the selection committee for selection of members has also been constituted.

The constitution of the Gujarat Electricity Regulatory Commission has been notified under the Regulatory Commissions Bill and the process of selection of the Chairman and members of Commission is already underway. This process, however, will not provide a mechanism for restructuring of the GEB. The state is thus also considering separate state legislation providing for comprehensive reform programme.

Andhra Pradesh

The State is well on its way towards the reforms and the legislative assembly passed the AP Electricity reform bill on 28 April 1998. The presidential assent has been received for the same. The government would now notify a date from which the new act would come into effect, which would pave the way for the formation of an independent and statutory three-member power regulatory commission. The restructuring programme involves reorganization of Andhra Pradesh State Electricity Board (APSEB) into two corporations under the Companies Act, India namely the APGENCO, having the generation business of the state, and APTRANSCO, having the transmission and the distribution business. APTRANSCO would be in the business of purchase of electricity from various sources, transmission, and supply of electricity. It will procure power from APGENCO, APGPCL, central generating stations, neighbouring states, and IPPs and will supply it to DISCOMs.

The state has also drawn out a detailed time-table for reforms. Immediately after the notification of the Reform Act in January 1999, the state plans to unbundle and corporatize the generation, transmission, and distribution business. The distribution is proposed to be separated into three different companies. The eventual privatization of those distribution companies has been scheduled towards the end of the year 2000.

Andhra Pradesh has followed the Orissa model and the first phase of the reform programme is about to be completed. It is expected that the progress will be rapid as compared to Orissa as the state has, in the recent past, demonstrated strong political will to improve the infrastructure and to attract private investment into various sectors of the economy.

Other states
A number of other states including Rajasthan, Karnataka, Tamil Nadu, Madhya Pradesh, the West Bengal are under the process of setting up the State Regulatory Commissions and restructuring the power sector. West Bengal is reportedly following a significantly different structure whereby all the distribution in the rural areas is handed over, by the board, to a new organization called the State Rural Electrification Development Corporation. This organization is expected to be structured as rural cooperatives buying power from the SEBs and managing their affairs at a local level. So a number of different structures and variations within structures are being undertaken in different states.

Market structure

Supply side

The electricity industry in India has traditionally been owned and operated by the government organizations. The Ministry of Power (MoP), Governmet of India is the primary body responsible for development of electrical energy in the country. Under the central government there are several agencies, and power generating and transmission entities that function under the administrative guidance of the MoP.

The construction and operation of generation projects in the central sector are entrusted to central sector power corporations, viz., theNTPC, theNHPC, the North Eastern Electric Power Corporation (NEEPCO). The Nuclear Power Corporation (NPC), under the administrative control of the Department of Atomic Energy, is responsible for the nuclear power plants.

The PGCIL is responsible for all the existing and future transmission projects in the Central sector and also for the formation of the National Power Grid. The PFC provides term finance to projects in the power sector. The REC, under the MoP, funds programmes of rural electrification.

The responsibility of generation, transmission, and distribution of electricity in the states is entrusted to the SEBs and departments. Most of these are vertically integrated utilities under the direct control of the State Ministry of Power or Department of Power. The SEBs came to be established in various states pursuant to a mandate contained in Section 5 of the Electricity (Supply) Act, 1948. There are 17 SEBs in operation and they generate over 70% of the electricity supplied in the country. SEBs not only generate, transmit, and distribute power, but are also responsible for fixing tariffs and collecting dues from the consumers. The Electricity Supply Act, 1948, envisaged the SEBs as economic and efficient organizations operating on quasi-commercial principles.

Private utilities form the smallest part of the power sector in India and its role till the beginning of reform programme was confined to specific areas of small jurisdiction and consumer base. The private sector organizations in the power sector have performed consistently well. They have generally been profit-generating organizations and are now regarded as role models for the new companies entering the sector. The major players in the private sector have been the BSES Limited distributing electricity in Mumbai, Maharashtra, CESC Limited in Calcutta, West Bengal, Tata Electricity Company Mumbai, Maharashtra, Ahmedabad Electric Company, Ahmedabad Gujarat, and Surat Electric Company,Surat, Gujarat.

Demand side

The consumption of electricity in India has experienced a rapid growth during the current decade. The growth has been consistently over 8% during the current decade with 1995/96 recording a growth of 8.5%. It has, however, increased at somewhat lower pace during the past two years. The per capita consumption has increased from 253 kWh in 1990/91 to 335 kWh in 1995/96 at a CAGR of approximately 6%. The number of consumers during the same period has grown from 82 million to 86 million. Most regions of the country continue to experience significant shortages with peak deficit being 11% and energy shortage being 8% during the last year.

Industry has traditionally been the single largest consumer of electricity in the country accounting for more than one-third of the total consumption last year. In the last decade, the share of industry in electricity consumption has come down from 62% in 1980 to about 38% in 1995/96 despite high industrial growth. The reason behind this is that the SEBs have, over the years, artificially inflated agricultural sales by including part of commercial losses as sales in this category. This is reflected in the consumption of the agricultural sector increasing from 12% to approximately 31%. This has been possible because of lack of proper metering for this segment of consumers.

Consumers in India have been the most neglected part of the state owned and operated infrastructure sector. There are not many organized forums where an aggrieved consumer can voice his or her complaint. Providing better quality of service and protecting the interest of consumers is one of the key elements of the reform programme. A part of the exercise of consumer education and awareness will have to be carried out by the regulatory commission. However, at the same time a movement to educate consumers on their rights, collect and disseminate information on the regulatory decisions and their impact on different consumer categories, spread awareness on the quality standards and mechanisms available for handling consumer complaints will have to be initiated.

Drivers for regulatory reform and change in market structure

The functioning of the industry has been characterized by the inability to achieve need/based growth, problems of operational, technical, and financial instability, which include *interalia*, high transmission and distribution (T&D) losses, low plant load factor, poor finances of the SEBs, etc.

The key drivers of the reform process can be identified as following

Economic and financial

Lack of financial resources with both the central as well as the state governments, to take up need- based programmes for generating capacity addition and development of T&D system. This has led to the recognition of the fact that the development of the sector cannot be undertaken without the participation of private capital. The key aim of the process is to make the environment attractive for investments by domestic as well as foreign private sector.

The widening gap between the demand and supply has put the government under pressure to open the sector and simplify the procedures and processes for approvals of projects.

Political and managerial

The functioning of most of the SEBs has traditionally been characterized by extensive political interference. This constrained the managerial and functional autonomy of the SEB administration, often leading to decisions, which were not based on commercial considerations. A number of social policy goals, for example, employment and price stability have often been interrelated to the government policies on the development of the sector.

Further, the electricity tariffs in most states are highly distorted with an element of cross-subsidy built into the tariff structure. The industrial consumers, supplied power at high tension, pay more than the domestic and agricultural consumers who are supplied at low tension. This is leading to an increase in captive power units which could eventually deteriorate further the already poor financial condition of the respective boards.

Technical and operational

The operational performance of the plants run by the SEBs has not been at par. The level of T&D loss is in most of the states is very high in comparison to the international standards. This problem, however, is often linked to the lack of financial resources and political interference in the functioning of SEBs.

Availability of reliable and quality power when demanded by the consumers has been lacking. The reform process has recognized the need for renovation and modernization of old plants and introduction of new and better technologies in the sector.

Restructuring of the sector and market development in the future

Since early 1990s, it was clearly evident that fundamental structural reforms need to be initiated to improve the performance of the electricity industry and to meet the rapidly growing demand. Reforms in the sector essentially focus on three issues, which are restructuring to improve efficiency of operation, regulatory reform, and competition and privatization. It is, however, important to note that the reasons for poor performance have been complex and diverse. Similarly, there are significant differences with respect to current state of development, level of performance, income distribution, and social concerns related to pricing and availability of electric power, legal and political systems, etc. in different states. Hence, it is not advisable to apply a one-size-fits-all approach which can severely limit the performance improvements that the reforms expect to achieve.

Various models of structuring the industry have been mooted and applied in various countries. Based on the degree of monopoly existing in the electricity sector around the world three generic models as detailed under could be considered.

Monopoly at all levels

A single company has monopoly over generation, transmission, and distribution of electricity to final consumers. Generation is not subject to competition and the customer has no choice of supplier. The model prevailed almost universally until quite recently.

Competition in generation

There is competition in generation but all the sales must be to a designated purchasing agency.

Retail competition or direct access

Here the customers choose their supplier. More than one supplier offers to supply electricity to consumers in an area. There is open access to transmission and distribution system. The distribution is separate from the retail activity, and the latter is competitive

There are many dimensions to the choice of industry structure and many different variations exist based on the characteristics of the individual country. In India, the restructuring of the electricity board would involve unbundling its functions, corporatization of its functions in one or more corporation, transfer of assets, liabilities, personnel from SEB to corporation(s), etc. There are several advantages associated with the unbundling of generation, transmission, and distribution business. These include transparency and accountability in the performance of different functions and hence ensure that all activities get a proper focus. Further, unbundling allows competition in the segments where it is likely to lead to optimal solution or at least a benchmark comparison amongst the functioning of various units.

State Electricity Regulatory Commissions - through notification or reform bill ?

Since the issue of unbundling and corporatization involves complex technical and social changes, it is important that the restructuring exercise should have the legislative sanction as legislation carries the backing of elected representative and hence public support. A legislative action is generally not open to challenge on grounds of malafide and other similar grounds whereas an executive action can be.

With the enactment of the Electricity Regulatory Commission Act, 1998, the state governments have two options for establishing the SERC. These are through a notification under the provisions of Section 17 of the Central Act or through a comprehensive state legislation with the requisite presidential assent.

Some of the state governments are reportedly going for the first option as it precludes the need for going to the state legislature, referring the bill to the central government, etc. and may, hence, work out to be a quicker and easier way to establish the SERC. However, this option has certain inherent drawbacks. First of all, the Central Act does not provide for restructuring of the electricity industry in the state, which should also be an integral part of a reform programme. It is also to be kept in mind that in the case of an SERC set up through a notification, the state government will have powers to curtail its power or even demolish it at a later date through a simple notification without going to the state legislature. Further, the political will and bureaucratic zeal will be important factors to ensure successful implementation of a reform programme. Thus, it is all the more desirable that the state government takes the initiative and owns up the reform programme.

Role of regulator

Establishment of an independent regulatory commission is one of the basic requirements of the reform programme. With the constitution of the same, the regulatory functions of the SEB will be transferred to the Commission and the role of state government will be restricted to issuing policy directives. The Commission should have full financial autonomy and it will be required to act in a manner that ensures that the interests of all stakeholders, including the regulated utilities, consumers, state, and others concerned with the development of the industry are taken into account. The specific functions of the Commission would include, among others, the following.

- To promote efficiency, economy and safety in the use of the electricity in the state including and in particular in regard to quality, continuity, and reliability of service and enable all reasonable demands for electricity to be met.
- To regulate the purchase, distribution, supply, and utilization of electricity, the quality of the service, the tariff and the charges payable keeping in view both the interest of the consumer as well as the consideration that the supply and distribution cannot be maintained unless the charges for the electricity supplied are adequately levied and duly collected.
- To regulate the working of the licensees and to promote the working in an efficient, economical, and equitable manner.
- To require licensees and others to formulate prospective plans and schemes in coordination with others for the promotion of generation, transmission, distribution, and supply of electricity.
- To regulate the assets, properties, and interest in properties concerning or related to the electricity industry in the State.
- To promote competition, competitiveness, economy, and efficiency, while ensuring a fair deal to the customers and entities engaged in business of generating, transmission and supply of electricity.
- To promote efficient utilization and conservation of energy, appropriate demand- side management, reduction of wastes, and losses in the use of electricity.
- To advise the state government on matters concerning electricity generation, transmission, distribution, and supply in the state, as the Commission considers appropriate and.
- To adjudicate upon the disputes and differences between the licensees and to refer the matter for arbitration.

The above list provides the detailed list where the regulatory body will have a role to perform. However, given the current status of market evolution there are several issues regarding the ensuring autonomy, accountability, independence, and expertise available with the regulatory commission. Further, as the market structure evolves from being a SEB monopoly to competitive entities in the private sector, the regulatory authorities would need to demonstrate the flexibility in approach. They will have to ensure that there are sufficient safeguards to protect the interests of the consumers and that the financial viability of the new entities is secure. They will encounter several implementation issues involving complex social, technical, legal, and economic issues in trying to achieve the stated objectives. They will hence need assistance on several fronts to ensure that they are able to meet the challenges set forth to them by a dynamic and evolving market.

In respect to the independence, autonomy and accountability, the following guidelines provide the basic framework.

Independence

The regulatory authority should be provided full independence from political pressures – from ministries and from regulated enterprises, private or public. To ensure this,

- the regulators should be appointed on the basis of professional rather than political criteria,
- the regulators should be appointed for fixed terms and should have formal protection from arbitrary removal during their term,
- their appointment process should involve both the executive and the legislature, to ensure proper checks and balances, and
- they should not have been employed recently by the regulated utilities or other interest groups. Further, there should be cooling period between end of their appointment and employment by parties with interest in the commission's decisions.

Autonomy

Autonomy would imply that a regulatory agency should have:

- the regulatory commission should have its own resources, based on its own funding sources (most common mode is through levies on regulated firms or the consumer of the regulated services), instead of relying on budgetary transfers;
- further, regulators should have autonomy in staffing, so that they can recruit staff with high levels of expertise. Thus, the tasks of the agency should determine the size of the staff, not political considerations. Achieving staffing autonomy in regulatory services often requires exempting them from civil service salary and recruitment rules. It might also mean recruiting external consultants as well.

Accountability

This requires:

- transparency in the regulatory agency's decision making process which requires the regulatory agency to publicly announce and invite suggestions at the initiation of a process to make policy decisions and to explain the policy decisions. This further requires that the decisions by regulatory agencies should be open to judicial review,
- clear simple procedural rules, which reduce possibilities of administrative delays,
- a multi-member commission reduces the possibility of abuse of power and

sudden and dramatic changes in the policy with a change in the regulator, and

- defined rules and procedures for removal of regulators need to be in place

Tariff setting

Current rate policies and their impact on consumption and resource allocation

The current pricing method used by most utilities in the Indian electricity industry is the traditional cost plus method. The regulatory mechanism for setting electricity tariffs is outlined in Schedule VI of the Electricity Supply Act, 1948. The cost plus approach starts with identification of costs which include the fixed costs related to capacity, the variable costs related to fuel, and other customer related costs. The procedure then is to allocate these costs as "equitably" as possible among consumers through the tariff structure.

The guiding principles for retail tariffs are usually financial and social. It is usually the intention of policy-makers that the level of tariffs is such that it meets certain financial criteria and the structure should, in some sense, be fair, and not penalize certain groups arbitrarily. Despite these guiding principles tariffs have evolved in an ad hoc manner in the past 30 years. Electricity tariffs have been used and are currently being used to meet several financial, political, and social objectives. The cumulative effect of such forces has created a complex web of tariffs in most states throughout India.

Typically, electricity prices in India are less than the cost of electricity production (average cost) and substantially less than the cost to build and operate a new power plant (marginal cost). During the financial year 1996/97 the average realization was about Rs 1.49/kWh while the cost of supply was about Rs 1.86/kWh. Compounding the problem of under-pricing is the high level of transmission and distribution loss and poor collection rate from farmers and domestic consumers. Electricity prices are also low in India compared to utilities in a number of other Asian countries.

Under-pricing of electricity is a serious issue in India's power sector. Under-pricing encourages consumers to place little value on saving energy. In many states, electricity to agricultural sector is not only under-priced but actually sold free (for example, in the states of Punjab and Tamil Nadu). Most states follow a flat-rate tariff structure for their agricultural consumers where farmers are charged on the horsepower of their irrigation pumps and not on the actual electricity consumed. Subsidies for agriculture electricity also create excess demand for electricity and disincentives for investments in conservation. More important, high demand makes power supplies unreliable, forcing consumers to maintain back-up generators, which results in macroeconomic distortions due to overcapitalization in the economy.

Problems with retail electricity pricing based on accounting costs also constrain efficiency investments for several reasons. Most customers pay for electricity based on total kWh use over a certain period with no distinction between use in peak period (when electric power is expensive to supply) and off-peak period (when electric power is relatively cheap to supply). This lack of price signals discourages load management actions. Second, with the exception of large industrial customers, most customers do not pay for poor power factor. Poor power factor leads to increased transmission and distribution losses, thereby raising the cost of power delivered.

Any analysis of power tariffs should consider both the structure of tariffs and the costing methodology for rate making. In the electricity economics literature it is fairly well established that accounting costs are not relevant for resource allocation. One reason for this is that the accountant is concerned with recovering sunk costs whereas, for efficient resource allocation, it is the actual resource used or saved by consumer decisions that are important. Prices are the amounts paid for extra consumption, and need to be related to the incremental costs in meeting extra consumption. The accounting framework for tariff setting fails to capture this important principle. The backward looking estimate of the traditional approach may lead to over-investment and waste or under-investment and unnecessary scarcity.

Objectives of the pricing policy

The demand for electric power in India is growing at a rapid pace and the objectives of economic growth require that the pricing policy should promote economically efficient allocation of resources, both within the energy sector and between it and the rest of the economy. At the same time, however, every citizen's basic right to be supplied with a certain minimum amount of energy needs to be recognized. Recent studies in some of the states have demonstrated the willingness and ability of consumers, including agriculture and domestic, to pay for efficient and reliable power at rates significantly higher than currently being charged. There is a need to reduce and gradually phase out the subsidies over a period of time, while at the same time improving the quality of supply.

Further, the pricing policy should ensure financial viability, autonomy and speedy development of the energy sector. In India, this aspect has been often overlooked, to provide subsidized power to agriculture and residential sectors. The utilities can not function in vacuum, and tariffs have to be correlated to the quality of power supplied with incentives and penalties awarded, for achieving the requisite standards and vice-versa. Introduction of Performance based tariff structure is expected to provide incentives to the utilities to improve the quality of supply and services provided by them.

On the consumption side, energy pricing is a very important tool for demand management, especially in the long run. Incentives for maintaining high power factor and for conservation during peak hours and seasons are required. Provision to impose penalties on those indulging in theft and violating the load control measures and adoption of proper incentives for adopting metered supply should be a part of a pricing policy.

Finally, there are a number of additional objectives such as the need for price stability, and the need for simplicity in energy pricing structures, promoting regional development or specific sectors, and other socio-political, legal and environmental constraints. Thus, a large number of complex issues need to be addressed and apparently contradictory objectives have to be reconciled while designing an appropriate pricing policy. In India, absence of reliable data and lack of infrastructure to implement innovative tariff structures further complicate the matter. Some progress has however been achieved with the initiation of reforms in the states of Orissa and it is expected that as the liberalization of the sector gathers momentum these constraints will be removed.

Efficiency pricing: the case for marginal costs

The rationale for using marginal costs is the maximization of economic efficiency and social benefits. Pricing below marginal cost results in wasted resources because the cost of producing some units exceeds their value to consumers. Use of marginal cost methodology promotes better utilization of capacity, and avoids unnecessary investments to meet peak demands, which tend to grow very rapidly. The marginal cost approach permits the structuring of prices so that they vary according to the marginal cost of serving demands: (i) by different consumer categories; (ii) in different time of the day; (iii) in different seasons; (iv) in different voltages; and so on.

Marginal cost approach as a basis for determining the fair price of energy provided by a new generator is immediately obvious. Assuming that the inflation impact exceeds the cost reducing impact of technological development, which is usually the case for most mature technologies, the embedded cost (of other generators already in production) is unlikely to provide sufficient financial incentive for new investments to come on-line. Hence, the need for adopting a marginal cost-based PPA for all new generators.

Moving towards LRMC tariffs in the retail segment will be the key to improving electricity efficiency. This is, however, easier said than done. There are several practical problems related to applying the marginal cost based approach in India. Traditional price regulation as carried out in India has been a socio-political exercise. It is unlikely that any government would allow the kind of rate "shocks", which moving towards LRMC tariffs would entail. Further, the revenue derived from charging marginal costs may differ significantly from the amount required to meet the financial needs of the licensee. This could either place the financial viability of the licensee in jeopardy or bestow a significant windfall upon it, unless the regulatory commission intervenes to correct the discrepancy. The data requirements for adopting marginal cost approach are comprehensive and complex than those required for using the accounting costs. The kind of data required is generally not available with most SEBs and the MIS systems are either non-existent or are not geared to meet these requirements. Hence, as a first step, the marginal cost approach may be used only as a "comparator" to provide signals to the regulator and the consumers.

Performance based regulation (PBR)

The performance-based rate making strives to eliminate some of the control aspects of regulation and replace them with a system of incentives and penalties. The prices in such a system are generally fixed for a longer period as compared to the cost plus methodology. PBR system has distinct advantage in terms of providing an incentive to the utility to minimise the costs. This incentive however needs to be counter balanced by monitoring the prescribed quality standards so that the reductions in cost do not lead to a reduction in the supply standards. There are several mechanisms and parameters such as the generating plant reliability, transmission and distribution loss, outages at customer level, customer complaint handling and satisfaction etc. around which a PBR system can be designed. Most SEBs in the country are characterized by the lack of a proper MIS system and reliable data to design a good PBR system. Hence, in the Indian context, at the outset only simple and easily measurable or quantifiable parameters should be included in the PBR system.

A transition strategy

The pace of reforms especially the tariff rationalization process will not be easy and is not possible in the short term. It will be constrained by several socio-economic ranging from factors like capability and willingness of consumers to pay for high cost power to a possible outcry and revolt against the incumbent regime. Political will is an important issue and will play an important role in determining the ultimate success of the tariff reform process on which the success of the reform programme will hinge. The following steps need to be initiated urgently to respond to the issue of rationalizing the tariff structure.

Establishing the regulatory structure

Setting up a regulatory commission fairly quickly is an essential task, which needs to be under taken by all states. The periodic revision of tariffs is a major problem as it has traditionally been a political decision. Many states in the recent past have dragged their feet for a long time over the issue, which has led to a deteriorating financial health of the SEBs. Setting up regulatory agency to do the job would de-link the government from what is considered to be an unpopular decision. The regulatory authority will take over this responsibility and set tariffs that achieved twin objectives of ensuring financial viability of the entities in the sector and at the same time insulating small and marginal consumers from price shock.

Sensitizing public representatives

The political leadership all over the country has been extremely sensitive on the issue of subsidies and has strongly held the view that any tinkering with the subsidies would be politically damaging. The public representatives need to be sensitized to the fact that further continuance of subsidies would be disastrous to the development of the sector. Further, through the process of reforms, it is possible for the government to de-link itself from taking unpopular decisions by setting up regulatory agencies to do the job.

Consumer education

Consumers in India have been the most neglected in the state owned and operated infrastructure sector. There are not many organised forums where an aggrieved consumer can voice his or her complaint. Providing better quality of service and protecting the interest of consumers is one of the key elements of the reform programme. At the same time it is critically important that the people in the country recognize the fact that subsidies have resulted in a substantial loss to the SEBs and to the economy as a whole. A vigorous campaign to educate the people about the financial crisis of the SEB's and to make them realize that further development of the sector is not possible without sufficient availability of resources with SEB's, needs to be launched. A part of the exercise of consumer education and awareness will have to be carried out by the regulatory commission. However, at the same time a movement to educate consumers on their rights, collect and disseminate information on the regulatory decisions, and their impact on different consumer categories, spread awareness on the quality standards and mechanisms available for handling consumer complaints will have to be initiated.

Graduating the tariff shock

In spite of the improvement in the general economic environment and income levels, a substantial portion of the country is not in a position to afford the electricity services. The regulators will need a mechanism, which ensures that low-income consumers do not lose access to electricity, while raising prices to marginal cost. This apparent paradox can be solved in two ways. The classical solution will be to pay direct person-oriented subsidies to poor consumers and raise power prices, instead of obliging utilities to reduce prices below costs, and then shouldering the debt, as is the current practice in India and several developing countries. This method however, is clearly impractical and an alternative could be to preserve low prices for the level of consumption prevailing before reform, but to raise prices at the margin. Consumers would then pay flat rates for current consumption levels, but prices would rise steeply if demand, especially the demand for higher (peak) capacity but not for longer utilization hours of the same capacity, were to increase. This would provide the right pricing signals for load growth.

Pacing of reforms and strategies for future action

There are different approaches for implementing the reform programme. There is a "big bang" approach where unbundling, privatization, and introduction of competition are achieved in a single step. The other approach is a phased reform process where relatively long transitional period is available to the utilities and the regulatory bodies to evolve according to a structured programme. Adoption of a particular approach would depend on factors like the existing capacity of the legal, political and social systems, performance standard of the existing infrastructure, complexity involved in implementing the big bang approach, the time required to evolve effective regulatory structure and the political will.

In India, the restructuring of the SEBs may be attempted in a phased manner to avoid the shock associated with a major changeover. This will ensure that sufficient time is available for regulatory bodies to start functioning effectively and would also provide sufficient time to convince all stakeholders of the benefits associated with the process.

As a first step, the activities of the SEB should be broken into separate divisions, which operate on commercial principles, or as separate profit centres. This step is relatively easy to accomplish as it does not require any legislative action and does not mean shifting or reallocation of the staff. The activities can be divided into separate divisions based on the functional role, i.e., the generation, transmission and distribution business should operate as separate divisions. It is possible to further sub-divide the divisions.

- Generation business can be divisionalized based on the nature of the plants, i.e., thermal, hydro, non-conventional, etc.
- Distribution business can be divisionalized on geographical lines into zones of manageable size.

The divisions should operate as separate profit centres and must be provided with full financial autonomy and functional independence. The dealings between the divisions should be on commercial principles and they should maintain separate books of accounts. These steps would bring forth the performance of each of the divisions and highlight to the management, the need for support, attention, and improvement at different places. The process of divisionalization would facilitate the eventual unbundling into separate companies.

The misconception that reform programme *ispo-facto* means transfer of ownership to private sector or privatization needs to be removed. Privatization is not an absolute necessity or mandate of the reform programme. Though privatization is one of the important vehicles for achieving the objectives, it does not mean that restructuring of the sector cannot be achieved without privatization.

At the same time it is important to take note of several advantages linked with the private sector participation in the sector. A private sector organization creates hard budget constraints, sets high performance standards and depoliticizes the sector. It will ensure availability of the much needed financial resources for development of the sector and also bring in skills available in the private sector. The Government of India has already allowed the participation of the private sector in generation, transmission, and distribution business. A number of IPP's have already come on line and progress on several others is being made. The activity that needs increased penetration of private sector is distribution.

The various models for private sector participation in distribution that can be considered are: -

- joint venture;
- uutright sale of assets to a private company;
- public offering or floatation;
- leasing /franchise/long-term concession, etc. of business to private sector;
- management contract with private sector;
- sub-contracting part of the business or a small area of supply to co-operatives; and
- assigning a part of the distribution work, namely, billing and recovery of money, maintenance of meters and maintenance of small supply lines.

There are several advantages linked with the joint venture model, which has been adopted in case of Orissa. These are enumerated below.

- The state government will retain some say in the utility and can step in if the utility abandons or fails to perform. This is necessary as electricity supply is a public utility service and cannot be discontinued at any time. The risk of a private sector not performing can also be avoided. In the joint venture model the state entity can be given control of the utility in case of non-performance by the private sector.
- political and public perception discourages outright sale/lease or disposal of public sector units.
- employees' opinion to joint venture is less as compared to outright sale, lease or disposal.

The disadvantages linked with other options are:

- the staff problem;
- in the absence of an inventory, it is difficult to identify the assets to be sold;
- it may involve substantial amount to be invested by a private person to purchase the assets.
- public offering or floatation can be done only for the whole corporation that is the successor of SEB. Public offering or floatation cannot be done for any particular division. This option, therefore, assumes that the entire successor company will vest with one participant. This may not be, therefore, feasible.
- a long-term lease franchise or a long-term concession will also have the same problem as mentioned in the case of an outright sale.
- management contract does not give the participant an effective control over the employees.

In context to the pacing of reforms, the following issues are important

Experience sharing

The reform process in Orissa was initiated more than three years ago and since then substantial process has been achieved in establishing the regulatory structure in unbundling the SEB and in moving towards privatization. There are several states that are or are likely to follow the Orissa model. In this context, it is important that the experience gained in Orissa is available to these states in order to ensure that the process is smoother and faster as compared to Orissa.

The actual process in each of the states would definitely be influenced by the circumstances in each of the states, the level of economic development, the political will and the path adopted for restructuring of the sector.

Confidence building among the management and labour

In the reorganization of any industry, the issues relating to transfer of employees are very delicate and at the same time of great significance. It is important to adopt a correct legal and a pragmatic practical approach to deal with these issues. Restructuring is often equated with retrenchment among the labour. The labour unions need to be reassured and training and skills imparted so as to make them more useful in the new environment. The engineers often feel that with the privatization, further expansion of the SEBs would stop and their promotion avenues would decline. However, they need to be convinced that liberalization would bring in a much-improved scenario in terms of job prospects in the private sector and better emoluments.

The new environment will also require the regulated utilities to make several changes in their operations to come up to the expectations of the regulatory commission. They have limited institutional capacity and skills available to them to meet sophisticated data requirements and in successfully presenting their case. Understanding and appreciation of the new system will take some time and persuasion to make them aware of the benefits that will flow from the process. This will ensure the cooperation of the utilities, which will be vital to ensure the viability of the reform programme.

The new regulatory environment will demand new skills and expertise, which most managers (mostly engineers) do not posses today. Training and upgrading of skills will be one of the key issues to be dealt with the SEBs in context of the regulatory reforms. This will ensure that the people do not loose motivation and are not made redundant by the new environment. Specialized cells dealing with regulatory affairs with expertise in technical, economic, legal, and accounting fields will need to be set up.

In this regard, it is important that the terms and conditions of service on the transfer should not be in any way less favourable than those, which have been applicable to them under the current structure. Further, all benefits rendered before the effective date of transfer should be recognized and the period of service should be considered as continuous for the purpose of service benefit.

Research in regulatory issues

The restructuring exercise will throw up a large number of issues, which will need insight and research from perspective of different stakeholders. These inputs will be required at three levels, i.e., the regulatory commissions, the regulated utilities and the consumers. Debate and analysis of these issues and dissemination of information and findings will be important to ensure that the process is not hijacked by interest groups and that all objectives of the reform programme as envisaged are achieved.

Summary

The field of regulation and regulatory economics are still under evolution in India. There are several questions and issues that need to be debated and analysed in this context. It will be critical to ensure autonomy, accountability, transparency, expertise, and credibility of the new regulatory regime if the process of regulatory reforms is to succeed. Further, a clear understanding and working relationship between the state government and the SERC and also between CERC and SERC's will need to be established.

Though the reform programme has been initiated in many states, the pace and the direction are still not clear. Some of the states are likely to follow the Orissa example while others may set up the regulatory commission under the Electricity Regulatory Commission Act, 1998. Political will is an issue which will play an important role in determining the ultimate success of the reform. programme. Even where regulatory commissions are set up, the pace of reforms, especially the tariff rationalization process will not be easy and is likely to extend over several years. It will be constrained by several socio-economic issues ranging from factors like capability and willingness of consumers to pay for high cost power to a possible outcry and revolt against the incumbent regime.

sues for Session 1: Regulatory framework

- How to ensure independence, autonomy, and accountability of the regulatory commissions especially since there are no precedents and given the fact that the regulatory decisions have wide ranging implications?
- Is sufficient expertise available with regulatory commissions to analyse available information? How can they be assisted to ensure efficient and reliable functioning?
- What would be the role of the government under the new regulatory framework and how to ensure that the regulatory decisions are not usurped?
- With the enactment of the Electricity Regulatory Commission Act, 1998 the state governments have two options for establishing the SERC i.e,. through the above or by enacting a separate legislation. The pros and cons of each need to be analysed and debated.
- What would be the role of CEA under the new environment? To what extent does the role of CERC overlaps with CEA? How to ensure that the policies are consistent?
- What are the possible areas of overlap between the CERC and SERCs? What happens in case of inconsistency or conflict between the CERC and SERC?
- How to minimize delays in regulatory decisions?
- What could be a measure of performance of regulatory commissions?

Issues for Session 2: Market structure

- In the Orissa model, the generation business is not a licensed activity as it is supposed to be a competitive business. However, as the competitive environment is yet to truly emerge in the Indian scenario and most of the regions continue to suffer significant shortages, there is a possibility of exercise of monopoly of power by the generators. As the power purchase costs account for more than 60% of the total input costs, whether the generation business should also be under the direct control of regulatory commission is an issue which needs to be debated and analysed. With the constitution of CERC, the tariff for central sector plants owned by NTPC, NHPC and for IPPs supplying power to more than one state would be regulated. However, other plants with almost similar technical and operational characteristics would continue to be outside the purview of any regulatory control.
- What should be the long-term strategy for developing a competitive market? What would be the choice for the transition phase?
- What could be the role of RLDCs in promoting short-term economy and emergency power exchanges?
- One of the main concerns of the IPPs related to the inability of the SEBs to pay their dues to the power generating companies and fuel suppliers. Taking note of this problem, the Government of India has proposed the formation of

a new entity, the Power Trading Corporation (PTC) to act as an intermediary between the SEBs and IPPs with guarantee through the state funds available with the Reserve Bank of India (RBI). Though, the formation of PTC is a welcome step, it does not attack the fundamental problem of the bankruptcy of the SEBs and it is not clear whether the proposed PTC will be able to remain financially viable in the long run?

- How are grid security and reliability affected by the changing market scenario?
- What should be the role of the system operator under the new environment? How will the regional grids be operated and economic efficiency in power exchanges ensured? Is there a need for independent system operator?

Issues for Session 3: Tariff setting

- What are the possible alternatives for SEBs to reduce the subsidy and cross-subsidies in the tariff structure? How fast can they move?
- Due to rapid expansion in the number of consumers, most SEBs in the country today do not have adequate MIS to cope with the information and data requirements of a sophisticated regulatory set-up. In this context what is the minimum set of requirement, which the utility can meet and what is the realistic time-frame in which the information requirements can be improved?
- The consumers in India do not have access to information and are not organized. Under such circumstances who will undertake the responsibility for representing and protecting the interest of consumers and how could this be achieved?
- Even the utilities do not have any experience of the new regulatory set-up and would need assistance by way of specialized expertise to help them in the formation of tariffs, complying with the information requirements and presenting their case to the regulatory commission. Has this issue been given adequate attention and is sufficient assistance available to the regulated utilities?
- With the initiation of the reform programme, it is important that different components of the tariff structure are separated and information made available to the consumers and potential investors. This process will ensure that the envisaged divisionalization and corporatization of the SEBs takes place and will facilitate the introduction of competition and private participation in the sector. Are the SEBs in a position to unbundle their tariff structure and prepare accounts on that basis? Do metering arrangements for such an arrangement exist? How fast can these be developed?
- Is it possible, given the current state of development and information level, to a have performance-based rate structure? What are the possible

performance indicators that can be considered?

- Administrative procedures have a potential to create delays and undermine the regulatory decisions. How can these be minimized while ensuring that transparency of the process and the opportunities for judicial review are not compromised?
- Under the VI Schedule of the Electricity Supply Act, the licensee's are allowed to earn a return of 5% over the prevailing RBI bank rate at the beginning of the financial year. This provision where the return available varies from year to year has led to uncertainty in the investor community. Also if the return available to the generating companies is assured at 16%, by same rationale, should not the return to transmission and distribution companies be at least at the same level?

Issues for Session 4: Present and future strategies

- What are the lessons from Orissa and how to ensure that the mistakes are not repeated?
- What should be the pace of reforms?
- What should be the strategy to deal with stranded costs and grand fathering effects of past contracts?
- How should new PPAs be structured to promote competition and economy in operation?
- What are the issues related to transmission system planning and pricing in the changing sectoral scenario?
- How should employee-related issues be handled?
- Training and upgrading of skills at the SEBs is vital to ensure that the people do not loose motivation and are not made redundant by the new environment. How will this be ensured given the fact that SEBs have no money?

Appendix 1: Brief description of legislation guiding the power sector

The Indian Electricity Act, 1910

The Indian Electricity Act, 1910 was passed by the Legislative Council on 18 March 1910 and came into force with effect from 1 January 1911.

The Act deals with the supply and use of electricity and is applicable to the whole of India, except the state of Jammu and Kashmir. The Act is the legislation, which deals with the grant of licences to persons who wish to engage in the business of supply or transmission of energy and also for approval to non-licensees to undertake transmission, supply and use of energy. The 1910 Act is in five parts. Part I deals with the preliminaries including definitions. Part II deals with the grant of licences for supply of energy and matters related thereto including the performance and functioning of the licensees. Part II A deals with licensing of transmission. Part III deals with the supply, transmission, and use of energy by non-licensees. Part IV deals with general matters including those concerning the use of electricity by institutions such as railways, aerodromes, the constitution of advisory boards, etc.

The Electricity (Supply) Act, 1948

After independence, the Government of India enacted the Electricity (Supply) Act, 1948 (1948 Act). The Act came into force on 10 September 1948. The 1948 Act was enacted to provide for the rationalization of the production and supply of electricity and generally for taking measures conducive to electrical development. The Act was enacted to ensure coordinated development of electricity in India on a regional basis. It was felt by the government that this was a matter of increasing importance for post-war reconstruction and development. Further, it was also felt, that the absence of coordinated system, in which generation is concentrated in the most efficient units and bulk supply of energy centralized under the direction and control of one authority was another reason that was impeding the healthy and economical growth of electrical development in the country. It was also apparent that if the benefits of electricity are to be extended to semi-urban and rural areas in the most efficient and economical manner consistent with the needs of an entire region, the area of development must transcend the geographical limits of a municipality, a cantonment board or a notified area committee, as the case may be.

It was therefore necessary that the appropriate governments should be vested with the necessary legislative powers to link together under one control electrical development in contiguous areas by the establishment of what is generally known as the 'grid system'. It was under these circumstances that the Electricity Supply Act was enacted to facilitate the establishment of this system in newly

Power Sector in India

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Power Sector in India

The growth of the economy calls for a matching rate of growth in infrastructure facilities. The growth rate of demand for power in developing countries is generally higher than that of gross domestic product (GDP). In India, the elasticity ratio was 3.06 in the first Five Year Plan and peaked at 5.11 during third plan and come down to 1.65 in the 1980s. For the 1990s, a ratio of around 1.5 is projected. Therefore, in order to support a rate of growth of GDP of around 7% per annum, the rate of growth of power supply needs to be over 10% annually. The power sector, hitherto, had been funded mainly through budgetary support and external borrowings. But given the budgetary support limitation, due to growing demands from other sectors, particularly the social sector and the severe borrowing constraints, a new financing strategy was required. The government, as reflected in the new policy enunciated in 1991, has recognized the role of the private enterprise in the development of the power sector.

Power supply scenario in the country

Over years, the electricity supply industry in India has made significant progress. The installed generating capacity has increased 61-fold and annual electricity generation 93-fold between 1947 and 1997. The size and expansion of the transmission and distribution network has also increased substantially. Besides all urban centres, over 85% of the total villages of the country today have access to electricity. There has also been progressive inter-connection of power systems, at the state level to start with and then at regional level. The entry of central public sector undertakings into power generation and transmission helped further consolidation of the power systems in the country transcending state boundaries. A national power grid that had been approved in principle by the union government in 1981 may soon take shape.

In spite of the above-mentioned advances, the growth in power availability has not been able to keep pace with the growth in the peak demand. Peaking power deficit of the order of 18.3% and energy shortage aggregating to 9.2% were experienced during 1995-96. As per the projections made by the fifteenth power survey, the energy requirement and peak demand requirement which stood at 389721 MU and 60981 MW during 1995-96 are likely to increase to 569650 MU and 95757 MW respectively by the end of the Ninth Plan (2001-2). Indicative forecasts for energy requirement/peak power demand by the end of the Tenth and the Eleventh Plans are of the order of 781863 MU / 130 944 MW and 1058440 MU / 176647 MW respectively. Thus the requirement for electrical energy and peaking power in the country is likely to go up by over 170% and over 190% respectively in the next 15 years.

Current Capacity (MW)

	Coal	Gas	Diesel	Hydro	Nuclear	Wind	Total
Central Sector	19,058	3,588	0	5,214	2,225	0	30,085
State sector	33,861	2,203	376	16,221	0	50	52,711
Private sector	3,051	2,014	0	456	0	850	6,371
Utility	3,005	319	0	426	0	0	3,750
IPPs	0	1,383	0	0	0	0	1,383
Others	46	312	0	30	0	0	1,238
All India	55,970	7,805	376	21,891	2,225	900	89,167

Future technological direction and trends

Energy sources

The technology for power generation is closely associated with the type of fuel used. The primary energy sources for generation of electricity in the country are coal and lignite, oil and natural gas, nuclear power and hydro power. Each of these resources is discussed here briefly.

Coal

The coal reserves in the country are estimated to be around 201.95 billion tonnes according to the assessment carried out in January 1996. About 85% of the coal reserves are in the non-coking coal category. The coal reserves are spread unevenly in the country. The bulk of the coal reserves (73%) are located in Eastern Bihar, Orissa, and West Bengal; Madhya Pradesh too has a sizable coal reserve at 17.5% of the total.

The power sector is today the major coal consuming sector and the estimated requirements of coal in 1996-97 was 210 million tonnes which constitutes about 74% of the total coal produced. With the continued reliance on thermal power generation, which constitutes about 70% of the installed capacity in the country, the total quantity of coal consumed in the power sector is likely to increase substantially.

The coal available is medium to low quality with ash content of 30%-50% and considerable amounts of extraneous content. With emphasis on open cast mining technologies, the ash and extraneous content of coal are likely to increase further. Beneficiation of coal has been considered and found to be an economic proposition when the distance of coal movement for power generation is over 750 km. With 8%-10% reductions in ash content of coal, there could be considerable savings in the cost of transportation of coal and the operation and maintenance cost of the thermal power plants.

Lignite

Lignite reserves in the country are estimated to be about 24.40 billion tonnes. About 80% of the lignite reserves are located in the South Arcot district of Tamil Nadu. At present only a small percentage of the total reserves of lignite have been exploited. Considerable scope remains for the exploitation of the lignite in thermal power plants. The technology for use of lignite in power station boilers has been well developed and modern boiler designs cater to the high moisture content and low calorific value lignite.

Dry lignite carries with it the risk of spontaneous combustion and, therefore, transportation of lignite over long distances might be difficult. Therefore, the use of lignite might primarily be at pit-head-based thermal power plants. Lignite in Gujarat carries high sulphur content for which special boiler designs are available.

Oil and natural gas

India is short of crude petroleum and natural gas and has to depend on bulk imports of crude petroleum oil. The latest assessment shows that the recoverable reserves of crude oil are about 728 million tonnes and that of natural gas about 680 billion cubic meters. The bulk of the natural gas and oil resources in the country are located in offshore areas where exploration, drilling, and production are costly.

bout 5500 MW of gas-based power plants are in operation in the country. However, the ndigenous natural gas is in short supply even for existing gas-based power plants. The mport of natural gas is being considered from several countries. In some gas-based plants iring of liquid fuel has been possible and has been implemented. However, the development of liquid fuel-based thermal power plants has been very small and a total of 490 MW capacity is in operation in gas turbines and diesel engines.

Nuclear power

Nuclear power generation was started in India in 1969 with the commissioning of the Tarapur Atomic Power station with assistance from USA, which has the capacity of 2 x 210 MWe based on boiling water reactor (BWR) technology. This power station continues to operate and supply power to the Western Regional grid. All subsequent projects in India were based on the pressurized heavy water reactor (PHWR) technology. The first such power project was set up in Rajasthan with external assistance from Canada and subsequently these reactors have been fully indigenized and further developed. At present PWHRs are in operation in Kalpakkam near Chennai, Narora, Uttar Pradesh, and Kakarpara, Gujarat, and are based entirely on indigenous efforts.

The nuclear power programme in India is based on natural uranium in the first stage and the indigenous thorium resources. Available reserves of natural uranium can support a programme of 10000 MWe power generation based on PHWR Technology. Through indigenous efforts and requisite support from Indian Industries, technology for production of fuel, heavy water, and all other necessary components has been developed for establishing 220 MWe and 500 MWe power units. The country has gained 120 operating reactor years of operating experience, which has been entirely accident free. The technology for the PWHR is being further upgraded.

In the second stage of development of nuclear power, the fast breeder reactors (FBR) will be developed. These reactors are fuelled by plutonium recovered and reprocessed from the spent fuel of the first stage PWHR programme. A 40 MW (thermal) fast breeder test reactor is already in operation in the country and design works are in progress for a 500 MWe FBR for generation of power. In the second stage of the nuclear power programme, Uranium 233 from thorium will also be fired in the reactors in order to start the third stage programme. The third stage programme would be based on Uranium 233-thorium fuelled systems. India has vast reserves of thorium and these would be put to economic use in the third stage of the nuclear power programme. The available reserves of uranium in the country can support a nuclear power programme of 300000 MWe in this way.

The Nuclear Power Corporation has a programme for commissioning additional capacity in order to obtain a total installed capacity of 11600 MWe of nuclear power by the end of the Eleventh Plan.

Hydro power

India has a large number of rivers and as these rivers flow from their sources in mountain and hills, they provide plenty of scope for large-scale hydro development. In the country, there are three well-defined geographical regions, namely:

i. the great mountain ranges of the Himalayas,
ii. the Indo-Gangetic plain, and
iii. the Southern Peninsula.

The Himalayan ranges comprise three almost parallel ranges, namely, the Great Himala Ranges, the Middle Himalayan Ranges, and the Shivaliks. The Shivaliks provide maximum interest for hydro power development because they provide the possibility construction of large storage dams for the regulation of water flows in these rivers.

On account of wide fluctuations in the discharges in the Indian rivers, large storage capac is often required to balance out the flows in order to increase the firm benefits hydroelectric power. Run of the river type hydroelectric projects yielding substantial fi power are feasible only in the Himalayan rivers because in these rivers substantial wa discharges are obtained even during the winter months. Even small storage capacities creat on Himalayan rivers help to increase appreciably the firm benefits of power generation fro these rivers because of the even distribution of river flows.

The waters of the Indian rivers are utilizable for irrigation in the plains. Therefore, there is a special utility of multipurpose projects, which would provide hydro power, irrigation, and flood control benefits. Many of the early developments on the Indian rivers were of the multipurpose type.

The Central Electricity Authority undertook reassessment of the hydro power resources of the country in the 1980s, taking into account new information available on topographical feature and hydrology of the river systems and the technological advances. The reassessment o hydroelectric potential is based on water availability corresponding to a 90% dependable year. The firm energy has been converted into hydroelectric potential by applying a suitable system load factor. On this basis the total theoretical potential of the river systems in India a 60% load factor was assessed as 30117 MW, and the economic potential at 84044 MW.

In the context of developing hydro power, the potential for pumped storage schemes also merits consideration as these projects provide a means for obtaining additional peaking powe leading to better management of the system resources in meeting the demand. These too. however, are site-specific depending on geographic features, availability of water, and peak power for pumping.

In the western and eastern regions of the country, adequate potential of hydropower does not exist to meet the entire peak demand through conventional hydropower projects. In these regions pumped storage hydro power plants could provide the means for obtaining peak power while absorbing surplus off peak power. Keeping this in view, the CEA undertook a systematic survey of the country for identifying suitable sites for pumped storage plant development. These studies have identified major schemes, which are the most economic.

This survey restricted itself to identifying only very large and extremely high head pumped storage sites for various reasons including economy, large number of sites, and comparatively lesser imperative for pumped storage development. However, the development of these mega sites do offer various problems including mobilization of larger funds which may have a discouraging influence on many private developers.

Micro hydro power potential is an attractive technology for decentralized generation of electricity in certain hilly areas in which extension of the main power grid might be uneconomical because of long distances and the low load densities. Micro hydro power potential is mainly located on small streams that ultimately flow into the major rivers.

urthermore, there is a possibility of development of mini hydel power schemes on irrigation anals. As per the studies carried out by CEA, the total potential of such schemes is assessed o be around 6780 MW from 1512 schemes. The exploitation of such potentials is not xpected to effect the flow patterns downstream. Since many of these can serve decentralized ervice areas, these also offer good scope for development under private sector.

Technology upgradation

In order to support the massive additions in the generation, transmission, and distribution systems, adequate emphasis needs to be given to upgradation of technology for improving the quality, reliability, and cost effectiveness of power supply.

On the thermal generation side, the following measures need to be taken:

- greater reliance on reheat units, use of improved materials and designs, adequate emphasis on design margins, redundancy, and preventive maintenance;
- use of fluidized bed combustion (FBC) technology for minimizing environmental impact of coal combustion during the pre-combustion and combustion stages. bubbling fluidized bed combustion (BFBC) technology in 30-60 MW range and circulating fluidizing bed combustion (CFBC) technology for larger capacity units;
- use of CFBC technology, flue gas desulphurization (FGD) system and low NO_X combustion techniques;
- use of integrated gasification combined cycle (IGCC) involving conversion of coal to other forms for easier cleaning and enhanced efficiency; and
- establishing fly ash-based building material production units near ash disposal points in the future plants for gainful utilization of large quantity of ash produced in our thermal power plants. Stress on financial incentives and legislative measures apart from establishing a central organization for making available the technologies developed by various R&D organizations/institutions to prospective entrepreneurs.

On the hydro generation side, the area of interest for technology upgradation is:

- suitable civil engineering measures as well as adoption of new materials like ARCLOCK, BOFORS and coatings such as plasma nitriding for runners and other water-borne components could be considered for tackling silt-related problems after field trials;
- technology for site-assembly of split transformers and runners for overcoming transport limitations; and
- adjustable speed generating units for pumped storage and conventional hydro plants, digital turbine governor for enhanced performance of the generating units.

In the field of transmission and distribution, the following areas merit consideration:

- increased use of power electronics;
- use of multi-circuit, multi-voltage lines;
- adoption of new designs for towers like narrow-based, guy tower, etc.
- uprating and upgrading of existing transmission lines;
- use of underground power cables;
- introduction of SF6 breakers; and
- adequate provision of better quality meters.

POLICY ON PRIVATE PARTICIPATION IN THE POWER SECTOR

With the objective of bringing in additionality of resources, for the capacity addition programme in the electricity sector, the Government has formulated a policy to encou greater participation by privately owned enterprises in the electricity generation, supply, a distribution field. The policy, in this regard has widened the scope of private investme the electricity sector, and has introduced modifications in the financial, administrative, legal environment for the private enterprises in the electricity sector towards mak investments in the sector by private units attractive. Based on this policy, a scheme has be framed to encourage participation of private enterprises in power generation, supply, a distribution, the details of which are given below.

WIDENING THE SCOPE OF PRIVATE SECTOR PARTICIPATION

Private sector units can set up thermal projects – coal/lignite or gas-based, hydel proje and wind/solar energy projects of any size.

Private sector entrepreneurs can set up enterprises, either, as licensees, or generati companies. New licenses can be issued by the State Governments to private units, willing enter the electricity sector as licensee companies, i.e., as a licensee holding a licence issu under Section 3 of the Indian Electricity Act, 1910 to supply and distribute energy in specified area, which may or may not have a generating station(s).

Generating companies can now be set up in the private sector. This has been brought abo through an amendment to the Electricity (Supply) Act, 1948. Hitherto, only the Central State Governments, or both, could set up generating companies. Generating companies ca now set up one or more generating stations and offer to sell electricity to the grid, unlik licensees, who supply and distribute energy within a specified area and who may or may n have generating stations. It is possible for an enterprise to combine the functions of generating company in one area and that of a licensee in another area. The generati company will sell power to SEBs, on the basis of an agreement, and at a tariff based o certain parameters.

Distinct from utilities power plants in the private sector, are captive power plants, set up serve an industrial or other unit, which requires large/continuous supply of electricity an hence, a reliable source of electricity. Surplus electricity from captive power plants can b offered for sale to the SEBs.

MODIFICATIONS IN THE FINANCIAL ENVIRONMENT FOR PRIVATE SECTOR UNITS

Debt equity ratio up to 4:1 is permissible for all prospective private enterprise entrants (both licensees and generating companies) to the electricity sector, that is, a minimum of 20% of the total outlay should be the equity component, at least 11% of the total outlay must come through promoters' contribution. In the rest of the total outlay, which may be up to 80% of the total project cost, an amcunt not exceeding 40% of the total outlay, may come from Indian public financial institutions, but the remaining amount should be met from other sources. In other words, to ensure that the investor brings in additionality of resources to the electricity sector, not less than 60% of the total outlay for the project must come from sources other than Indian public financial institutions.

Up to 100% foreign equity participation can be permitted for projects set up by foreign private investors in the Indian electricity sector.

With the approval of the government, import of equipment by private utilities and electricity rojects can be permitted, in cases where a foreign supplier(s)/agency(ies) is/are extending oncessional credit.

The financial parameters laid down in the Electricity (Supply) Act, 1948 of the licensing companies with regard to rate of return has been raised [through an amendment to the Sixth Schedule in paragraph XVII 10(b) of the Electricity (Supply) Act 1948] from the two per cent as applicable over the Reserve Bank of India (RBI) rate, to the investments already made, to five per cent over the RBI rate for investments made after this amendment.

Special appropriations may be permitted by the State Governments each year to cover the higher debt redemption obligation of the licensee [Sixth Schedule, Paragraph XVII 2(c) (5b) of Electricity (Supply) Act, 1948], which was not the case earlier.

In the case of licensees, capitalization of interest charges during the construction period (between the date of grant of license and the date when the undertaking commences supply), as actually accrued, will be permitted to be included as original cost. This facility will apply to expansions also, after this amendment. The previous system was calculating the interest charges at one per cent above the average RBI rate. This amendment has been brought about in Sixth Schedule Paragraph XVII 6(b) of Electricity (Supply) Act, 1948.

MODIFICATIONS IN THE LEGAL FRAMEWORK: AMENDMENTS TO

(I) INDIAN ELECTRICITY ACT, 1910
(II) ELECTRICITY (SUPPLY)ACT, 1948.

Hitherto all electricity schemes above the value of Rupees 50 million had to be submitted to the Central Electricity Authority (CEA) for its concurrence. This ceiling limit has been made flexible and has been raised to Rupees 250 million. Henceforth, the ceiling limit regarding outlay of the schemes which is required to be submitted to the CEA for its concurrence will be notified from time to time as laid down in Section 29(1) of Electricity (Supply)Act, 1948.

Licensee companies will be granted licences of a longer duration of 30 years in the first instance and subsequent renewals of a longer duration of 20 years, instead of 20 and 10 years, respectively, as was the case before the amendments to the Indian Electricity Act, 1910 (section 6) came into force. This ensures stability in the operation of the licence.

The interpretation of generating companies has been amended [Section 4A of Electricity (Supply) Act, 1948] to mean a company registered under the Companies Act, 1956 which has among its objectives to establish, operate and maintain generating stations.

Generating companies can enter into a contract for the sale of electricity generated by it with the State Electricity Board in any State where it owns/operates generating station(s) or in any other state it is carrying on its activities or with any other person with the consent of the concerned state government. The amendment has been incorporated in section 43(A) (i) of the Electricity (Supply) Act, 1948.

Common Phraseologies in Power Sector

Power system

All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformers, and protective components necessary to provide service to the customers.

Grid

A network of electric power lines and connections.

Firm Power (or energy)

The electrical power or energy intended to be available at all times during the period of the agreement for its sale.

Non-Firm

Power (capacity) and/or energy available from surplus generating resources that is interruptible on very short notice.

Interruptible Power (or energy)

Power or energy made available under an agreement that permits curtailment or interruption of delivery at the option of the supplier.

Firm Exchanges

Take place when the selling system has surplus generating capacity and is in a position to supply power to a deficit system on a firm basis.

Emergency Exchanges

Cover import by a needy utility on account of loss of generation and/or outage of an important transmission facility.

Inadvertent Exchanges

Are actually unintended inter system power flows that take place due to the grid parameters prevailing at any given time, which keep on changing from moment to moment. These inadvertent power flows are a consequence of integrated operation of power systems.

Banking

Banking of power is the process under which the captive power plant or a cogenerator supplies power to the grid at a given time and draws back this power from the grid at a prescribed time

Wheeling

Wheeling is the movement of electricity from one system to another over transmission facilities of intervening systems.

Station Capacity

The maximum power capability of a generating unit or station.

Base Load

The minimum continuous load over a given period of time.

Peak Demand

The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Off-Peak Energy

Energy normally provided during off-peak periods to supplement or conserve fuel storage (fossil or hydro) of the receiving system.

Pit-head station

Generating stations located near the coal mines.

Base load station

Power plant designed to run to meet the base load demand.

Peaking stations

Generating stations operated to meet the peak demand are called peaking stations. The characteristics of these plants is that these can be switched on and off in a short period so as to meet the peak requirement.

Reserve Generating Capacity

The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons; (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Reserve Margin

In the Indian context, the available generating capacity is defined as the total system installed generating capacity, less planned outages, less forced outages, less partial outages. The difference between the installed and available generation is referred to as the Reserve Margin.

Operating Reserve/Spinning Reserve

Excess generating capacity held available on ten minutes or less notice for use by another generation, e.g. fuel displacement.

Demand

Instantaneous electricity demand at a specified point in time, typically measured in megawatts.

Contracted Demand

Contracted Demand is the demand agreed to by the supplier or licensee for supply to the industry or any other user.

Load Diversity

When two electric utility systems in adjoining areas, or relatively close areas, experience peak loads at different times, the system loads are combined such that generating resources of both systems are better utilized.

Demand Charge

The component of a two-part price of electricity that is based on a consumer's highest power demand reached in a specified period, regardless of the quantity of energy used.

Energy Charge

The component of two-part price of electricity, which is based on the amount of energy consumed.

Plant Load Factor (PLF)

The Plant Load Factor is used to describe the percentage of capacity actually realized at an existing facility, and to estimate the available generation. PLF can be calculated as the ratio of electrical generation during a pre-established period of time, to the maximum possible generation during the same time period. The recommended definition of PLF is:

PLF = (Actual Generation) / (Maximum Possible Generation)

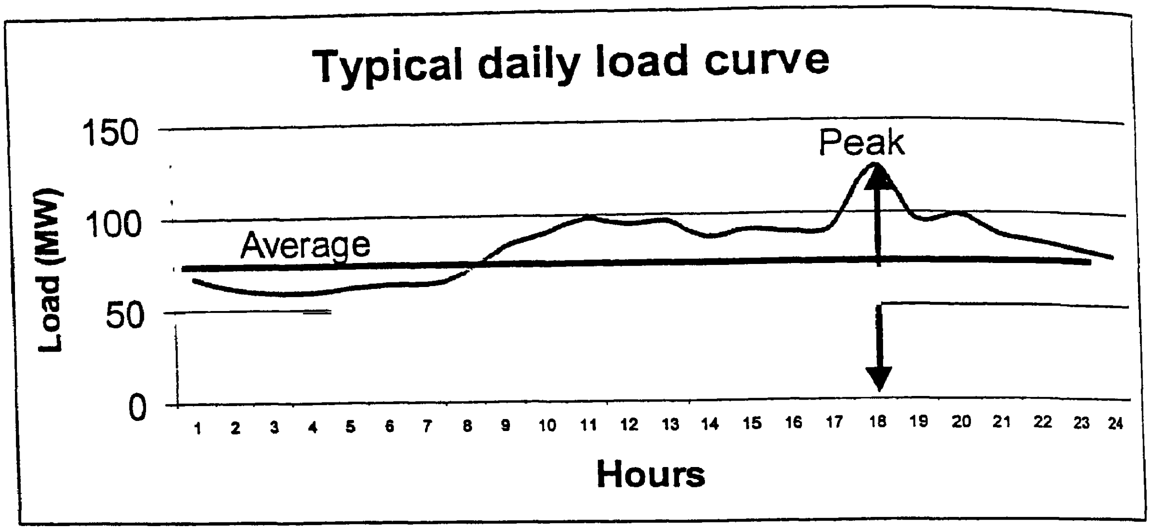
= (Actual Generation) / (Period Hours x Design Electrical Rating)

The PLF by itself does not provide any indication of the efficiency levels. For the purpose of economic evaluation of the plants the period considered for calculation of the PLF is 8760 hours. This does not take into consideration the various periods of part load operation. This PLF comprises of factors that influences the total output of the power plant. These factors may be (1) lack of demand, (2) forced or scheduled outages, (3) economic despatch considerations and other restrictions. These variations can be spread over the entire year or during a part of the year. If a power plant is in operation at a PLF of 50%, it does not mean that the plant has been operating at 50% of its rated capacity through out the period. There is no direct relationship between part load efficiency and the PLF.

Load Factor

It is the ratio of average load to the maximum load during a designated period.

$$\text{LF} = \frac{\text{Average load}}{\text{Maximum load}} < \text{less than unity}$$



The average load determines the energy consumption over the day (or a given time), while the peak load along with considerations of standby capacity determines plant capacity for meeting the load. A high load factor helps in drawing more energy from a given installation. As individual load centers have their own characteristics, their peaks in general have time diversity, which when utilized through transmission interconnection, greatly aids in jacking up load factors at an individual plant-excess power of a plant during the light load periods is evacuated through long distance high voltage transmission lines, while heavily loaded plant receives power.

Diversity Factor

This is defined as the sum of individual maximum demands on the consumers, divided by the maximum load on the system. This factor gives the time diversification of the load and is used to decide the installation of sufficient generating and transmission facility. If all the demand comes at the same time, i.e. unity diversity factor, the total installed capacity required would be much more. The high diversity factor could be obtained by:

(i) giving incentives to consumers to use electricity in he night or light load periods.
(ii) Staggering of office timings and
(iii) Having a two-part tariff in which consumers has to pay an amount dependent on the maximum demand he makes, plus a charge for each unit of energy consumed.

Power Factor

Electric power expressed as watts in d-c circuits is the product of the voltage and current (voltage times current). In a-c circuits the calculation is complicated by the need to take into account the shape of the voltage and current waveforms and their relative phase angle. If an AC load is purely resistive load, such as incandescent light bulbs and heaters without fans, then the power is indeed the product of volts and amps. However, there are three types of "power":

The **Real power** is mathematically determined by dividing time into a very large number of small segments and multiplying the instantaneous voltage present in each time segment by instantaneous current flowing and averaging the results.

A person may measure that a well pump consumers 220 volts and 10 amps. It would seem that this means it uses a total of P=220Vx10A=2200 watts. However, this is only a calculation of **apparent power**, which is really measured in VA and is not equal to the real power consumed. The well pump has a power factor associated with it. PF is the ratio of real power to apparent power.

PF = Real power/ Apparent power (or cos(phi), Phi being the phase shift between voltage and current)

The PF is used to compute real power. Real power is always expressed in Watts, while apparent power expressed in VA. The reason real power is important is that the power consumed by well pump is the real power which is converted into mechanical power, in this case from electrical power.

Magnetic load such as motors can draw more VA power than actual real power. The extra component is called a VAR (volt-amp-reactive) or **reactive power**. VAR is basically magnetic power, which causes a phase shift between voltage and current curves.

Gross Calorific Value

Fuels are naturally occurring materials when burned in air or oxygen produce potentially useful thermal energy. Calorific value is defined as the heat energy evolved by the combustion of unit quantity of fuel. In practice two types of calorific value may be defined: *gross calorific value* and *net calorific value*.

Gross calorific value, or high heat value, represents the maximum energy that can be derived from a fuel and is therefore measure of the total heat content.

The net calorific value, also known as the lower calorific value (LCV), assumes that the water formed by combustion and also the water of constitution of the fuel remains in vapour form. In industrial practice it is not practicable to reduce the temperature of the combustion products below dew point to condense the moisture present and recover its latent heat, thus the latent heat of the vapour is not available for heating purposes and must be subtracted from the higher calorific value. The difference between the "net" and the "gross" calorific value of a fuel is the latent heat of condensation of the water vapor produced during combustion of the fuel.

Heat Rate

It is defined as the amount of heat required for producing one electrical unit (one kWh).

Cogeneration

A Cogeneration Facility is defined as one, which simultaneously produces two or more forms of useful energy. e.g. electric power and steam, electric power and shaft (mechanical) power etc.

Tariff Setting in the Electric Power Sector

Base paper on Indian Case Study

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Tariff Setting in the Electric Power Sector
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Introduction

Tariff setting is a primary instrument of economic regulation. Tariff provides economic signals, which determine the volume and nature of demand and supply. It is not surprising therefore that a considerable portion of the reform effort is expended on rationalizing tariffs, often disproportionately so[1]. It is attractive to assume that the financial viability of the distribution business can be improved merely through technical corrections to the design and the level of tariff. The experience shows otherwise. Regulatory Commissions have been constrained from more efficient tariff setting due to the non responsiveness of public utilities to economic signals, continued poor quality, high cost and inefficiency of supply. Tariff reform can improve allocative efficiency by providing better price signals. It can increase the revenue inflow in those consumer classes where costs are currently under recovered. However, by implication, tariff reform will reduce the revenue inflow, at least in the short run, in those consumer classes, which currently cross subsidize others. The net financial impact of tariff reform can therefore be ambivalent from the near term perspective and crucially dependent on appropriate sequencing. For restoring the financial viability of utilities and bridging the revenue gap, tariff reform must be accompanied by adequate financial support from the government during the transition period and speedy and efficient restructuring of utilities along the lines of corporatization, commercialization and privatization.

It is now widely accepted that regulation is only a second best alternative. It is best when it can mimic market signals. The widely held view of the efficacy of regulation is the primary source of pressure on tariff regulators to behave like an efficient market. Since the markets are efficiency oriented, rewarding efficient agents and penalizing inefficient ones, the cost of service approach in tariff regulation has evolved into a performance based approach which incentivises efficient suppliers. Since markets provide elbow room to suppliers to mange their affairs without interference the Price or Revenue Cap approach to tariff setting was a subsequent development which attempted to mirror the free play of the market. The Retail Price Index approach is the most recent evolution in this trend.

India has a long history of experience with cost of service regulation. Its experience with performance based regulation is a decade old while it has no formal experience with either the revenue cap or the price cap or the RPI minus X approach. This paper identifies the financial imperatives for reform, reviews the evolution of the legislative basis and the nature of tariff regulation, evaluates the experiences with reform, surveys the literature and international experience, highlights unresolved issues and provides options for the future.

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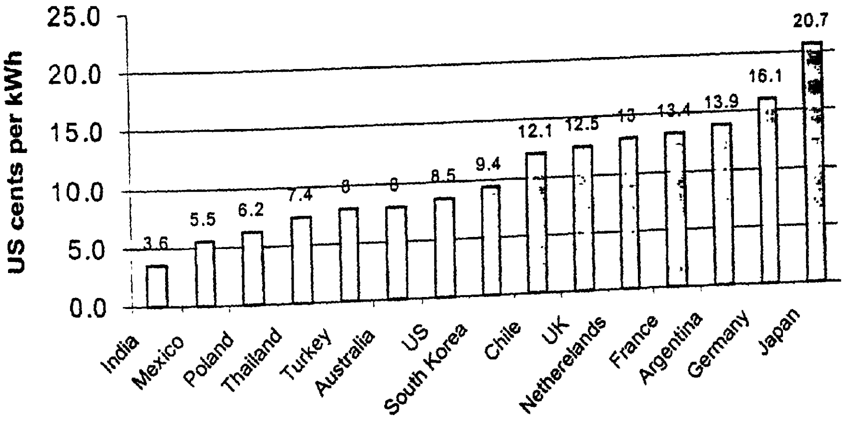
[1] Ahluwalia, Sanjeev S. "Tariff Reform in India; A review of directions and issues" in Transition to a Liberalized Environment, TERI 1999.

The financial imperative for reform[2]

The financial viability of the electricity business in India has worsened over time. The losses of the nineteen State Electricity SEBs (SEBs), which supply around 95 percent of electricity consumed, have increased from Rs 45.6 billion in 1993/93 to Rs 123.2 billion in 1998/99. If the opportunity cost of capital calculated at the minimum rate of 3 percent on net assets, prescribed by the Electricity (Supply) Act, 1948 [E (S) A] is added to the financial loss incurred by the SEBs, the loss in 1998/99 increases to Rs 187 billion.

High transmission and distribution loss, low utilisation of installed capacity, high manpower costs and distorted tariff are the factors contributing to the sub optimal performance. Agricultural and domestic consumers consumed nearly one half of the energy supplied in 1998/99. Both consumer categories are heavily undercharged. On an average, supply to agriculture recovered only 12 percent of the average cost of supply while supply to domestic consumers recovered only 54 percent of the average cost of supply. Conversely, supply to industry recovered 122 percent of the average cost of supply. If revenue realization is compared to the marginal cost of supply for these categories of consumers, the distortions become even more extreme. Graph 1[3] below compares average electricity prices in the domestic sector across developed and developing countries.

Graph 1: Household electricity prices in 1997



It illustrates the low average prices for household supply of electricity in India even as compared to some developing countries. Graph 2 illustrates the relatively higher prices charged to industry on average in India.

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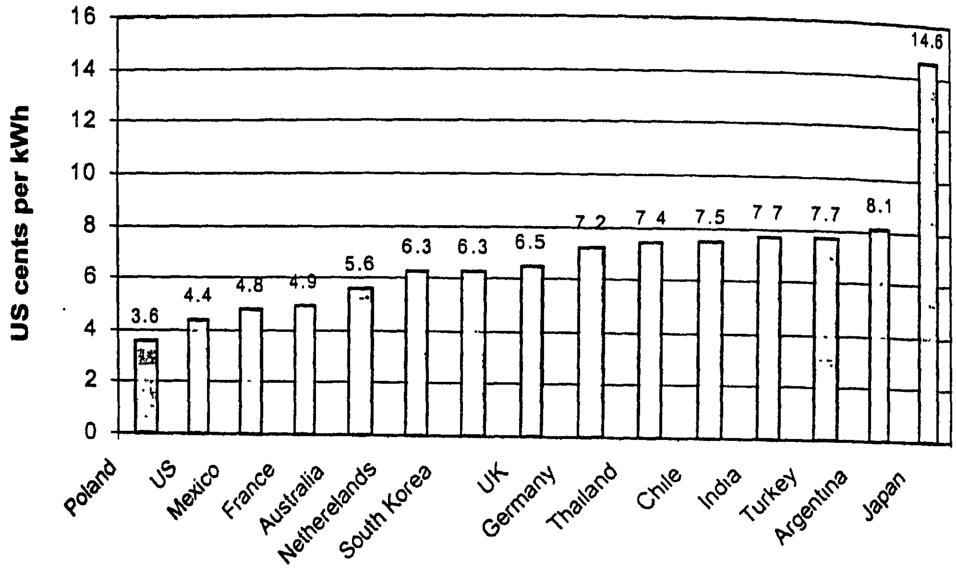
[2] This section borrows heavily from "The Electric Power Sector in India" a status paper, January 1999 prepared for the NCAER, New Delhi by Sanjeev S. Ahluwalia.

[3] Data Source: Energy Prices and Taxes- Quarterly Statistics, IEA, 1999.

Graph 2; Electricity prices for industry 1997



Electricity prices for industry in India are higher than most developed economies, excluding Japan, and several developing countries. This distorted tariff pattern in India has been designed to cross subsidize domestic and agricultural supply by charging industry more than the average cost of supply. In most SEBs, the tariff for industry exceeds even the marginal cost of supply. This has resulted in self-generation being increasingly adopted by industry as a cheaper and more reliable source of power, thereby further eroding the financial viability of the SEBs.

The financial position of the Licensees has generally been better because they were more efficient but also because they had a limited volume of agricultural supply and were able to bill and collect revenue from their domestic consumers who were primarily in the urban areas unlike SEBs which serve a mixed load in rural and urban areas. Similarly the financial position of the central sector entities like NTPC, NHPC and POWERGRID and functionally unbundled generators, like Karnataka Power Corporation, owned by the state governments was satisfactory because they have been insulated from the financial non-viability of distribution. However, as more and more SEB's get functionally unbundled and IPPs are established, all of which want contractual guarantees, reimbursement of fixed charges and in some cases minimum off-take, the inadequate revenue generation in distribution has become a barrier for incremental capacity installation. In the case of the central sector entities, the inadequate financial viability of the SEBs is reflected in the mounting dues, which remain unpaid by the SEBs.

SEB losses are financed from the budgets of state governments. These losses are partially offset by the receipt of subsidy from the state governments. State government finances have been under stress in the nineties. The revenue deficit of states increased from Rs 53.1 billion or 0.99 percent of GDP in 1990/91 to Rs 404.9 billion or 2.30 percent of GDP in 1998/99[4]. Relative to the total revenue receipts of the states, which is a fair indicator of the capacity of the states to subsidize the losses of the SEBs, the loss of the nineteen major SEBs increased from 5 percent of revenue receipts of the states in 1992/93 to 6.5 percent in 1998/99. If the opportunity cost of the capital invested in the assets of these nineteen SEBs is also accounted for, the loss of SEBs in 1998/99 increases to Rs 187 billion which is nearly 10 percent of the revenue receipts of state governments in that year. Since the state government finances the losses of the SEBs, financial imbalance in the SEBs has had a significant impact on the fiscal imbalance in state finances. Gujarat provides Rs 1260 crores per annum as subsidy while the allocation for power subsidy in Andhra Pradesh is Rs 1345 crores. These are resources, which the state governments are diverting from pressing requirements in the health, education and social welfare sectors. It is not surprising therefore that reform of the power sector should constitute a very major part of the more general process of economic reform and that within the power sector, attention should be focussed on tariff reform. It is however somewhat naïve to expect that tariff reform can be implemented in isolation of a change in the managerial effectiveness of public utilities or a restructuring of the industry.

Review of the Legislative provisions and trends in Tariff Setting[5]

Indian Electricity Act, 1910

The legal provisions for the regulation of tariffs of power utilities can be traced to the Indian Electricity Act 1910 (IE Act). However, in keeping with the perceptions of the times, there was no attempt at being prescriptive by specifying, either the principles, or the methodology to be followed for tariff setting, beyond enjoining that tariff must be non discriminatory and allow a reasonable return to the licensee.

Electricity (Supply) Act, 1948

The first attempt to closely regulate monopolistic power utilities by defining the basis on which tariffs could be charged was made in the Electricity (Supply) Act, 1948 [E (S) Act]. At the time there were two types of entities in the power sector; Licensees under the IE Act and State Electricity Boards (SEBs) created by the E (S) Act. Schedule VI of the E (S) Act prescribed the methodology to be followed for the determination of the tariffs of power utilities, which were Licensees under the IE Act. This is a detailed cost plus methodology where the rate of return on the capital invested is regulated and a cap is imposed on the clear profit of the licensee. In the case of Licensees it has worked satisfactorily from the viewpoint of financial viability of the utility. The E (S) Act also established the SEBs, which were expected to supplement the efforts of the private Licensees. Section 59 of the E (S) Act therefore provided the basis for tariff determination of the SEBs. As originally formulated, it simply enjoined the SEBs to adjust their charges from time to time so as not to conduct their business at a loss after accounting for subventions received from government. It also envisaged that there may be need to meet expenses on operation and maintenance from capital to be sanctio by the state government. This was clearly in sharp contrast to the existing provisions Licensees who were left free to recover charges as appropriate from the consumers. 23 of 1978 amended Section 59 of the E(S) Act to specify that the tariff was to be adjusted so that SEBs earned at least a surplus, after accounting for all subventions costs, including tax. The rate at which such surplus (defined as income less expenditu including interest and depreciation) was to be recovered was left to be specified by state government. Act 16 of 1983 further amended the section to the form in which stands till today. SEBs were required to so adjust tariffs so as to earn a surplus (defin as income less all costs, including interest on debt) of at least 3 percent. Sta governments could also specify a higher rate for the generation of surplus. Genera states did not actually do so and SEBs have been unable even to generate the specifi minimum surplus.

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[4] State Finances: A study of budgets of 1999-2000, January 2000, RBI.

[5] This section borrows heavily from the Central Electricity Regulatory Commission (CERC), Consultation Paper on Bulk Electricity Tariffs, September 15, 1999.

Till the establishment of central generating stations in the early 1980's, the industry wa dominated by private Licensees and vertically integrated SEBs. SEBs could purchas electric power from any person under the provisions of section 43 of the E(S) Act terms as agreed between the contracting parties. However no defining principles wer available for tariff setting and tariffs for individual stations were decided on the basis mutual consent between the generator and the consuming SEBs. The absence mandatory norms for tariff setting are said to have led to delays in settlement commercial terms and required extensive negotiation de novo for every station. This was perceived to be inefficient. Consequently the central government constituted a committee under the chairmanship of Shri K. P. Rao Member (E&C) CEA to recommend alternative methods for the determination of generation tariffs of central stations.

The recommendations of the K.P. Rao Committee can be regarded as a landmark in the history of bulk tariff regulation in India. Four recommendations, which were implemented significantly altered the tariff setting methodology.

> First, the concept of two-part tariff, comprising fixed and variable charges respectively was accepted, though it was only implemented in part. This enabled formal identification of the fixed cost incurred by the generator.
>
> Second, the concept of "deemed generation" was introduced, which delinked the payment of fixed charges from use. Henceforth generators were to recover their fixed cost even if an "available" station was backed down due to system constraint.
>
> Third, changes in risk allocation and efficiency linked returns were effected in the existing incentive structure. Till 1991, the single part tariff was calculated such that full recovery of fixed costs was assured at a PLF of 62.8 percent. Generation below this target level penalized the generator on the recovery of fixed cost, since the tariff got proportionately reduced. Conversely generation above 68.5 percent resulted in significant excess revenue. The formula adopted post 1991 limited both the incentive and disincentive for recovery of fixed costs. The incentive beyond 68.5 percent PLF was lower than before while even with nil generation. 50 percent of the fixed cost was recoverable.

Fourth, for the first time, operational norms were determined for station heat rate, auxiliary power consumption and specific oil consumption. More importantly, the norms were challenging relative to average performance levels at the time and hence laid the basis for Performance Based Ratemaking.

Act No 50 of 1991, introduced Section 43A of the E (S) Act, which specifies that in the case of government owned generating companies, the tariff would be decided by the state or central governments whoever owned the company. Tariff was determined on the basis of operational norms and PLF as determined by the CEA while the rates for depreciation and reasonable return were to be notified by the central government. It was under these provisions that some of the recommendations of the K. P. Rao Committee were notified by the central government and came to be used in tariff determination of central stations.

The Amendment Act No 50 of 1991 also changed the definition of "generating company" to include privately owned generating companies. Accordingly, a fresh set of norms were notified by the central government on March 30, 1992 to determine tariff for both thermal and hydro generating stations to be set up by the Independent Power Producers (IPP) in the private sector. These have been subsequently modified from time to time. Four primary changes were introduced in the determinants of tariff.

First, the recovery of fixed costs was linked to deemed PLF (defined as PLF plus Deemed Generation) thereby making a departure from the past wherein the recovery of fixed costs was linked only to the PLF achieved.

Second, the incentive structure was further revised. In the case of thermal generation the deemed PLF for full recovery of fixed charges was fixed at 68.5 percent. For hydro power the target availability was 90 percent (subsequently reduced to 85 percent in 1998). An incentive in the form of an increase in ROE of upto 0.7 percent points for every 1 percent point increase in deemed PLF was determined along with a penalty calculated as a pro rata reduction in the recovery of fixed cost for deemed PLF below the target level.

Third, along with the increase in the rate applicable for the central generators from 10 percent to 12 percent, the Return on Equity for IPPs was fixed at 16 percent per annum. Central generators in turn benefited from the rate set in 1991 for IPPs when on November 1, 1998 their return was also revised upwards to 16%.

Fourth, against the notional debt equity ratio of 50:50 for central generators, the debt equity ratio for IPPs was revised and the minimum level of equity fixed at 20 percent. The minimum stake of the promoter to be held as equity was fixed at 11 percent of the total capital. A cap was imposed on financing from the Indian Financial Institutions at 40 percent of total outlay (which has subsequently been relaxed).

Fifth, upto 100 percent foreign equity was permitted with foreign exchange risk protection

Transmission

Separate provisions for transmission tariff do not explicitly exist in any of the electr laws. This is not surprising since unbundled transmission did not exist till establishment of POWERGRID in *1989*. In fact POWERGRID is treated as a genera company under the definition provided in the E(S) Act. The assets of POWERGRID, sole central government transmission company, were transferred to it from NTPC a NHPC. Tariff was determined and notified by the central government on the basis techno economic approvals of investments given by the CEA. Consequently notification dated December 17, 1997 was the first attempt to formalize the methodolo of tariff setting. It prescribes a single part tariff comprising all costs on account of inter on outstanding loans and working capital, return on equity, depreciation, O&M expens as per norms and income tax. The full cost is recoverable at an availability of 95 perce An incentive is given in the form of increase in ROE at the rate of upto 1 percent point every 1 percent point increase in availability. A debt equity ratio within the norm of percent maximum and 20 percent minimum has been used for POWERGRID while rate of ROE is the same as for generation.

In 1998, prior to the coming into effect of the Electricity Regulatory Commissions A (ERC Act), five sets of norms for tariff setting were in force. One set of norms, specif by schedule VI of the E (S) Act, determines the retail tariff of Licensees under the IE Ac The second set of norms under section 59 of the E(S) Act determines the retail tarif SEBs. The third set of norms specified by the central government under section 43 A(of the E (S) Act determines the bulk tariff of central stations. The fourth set of norms under the section 43 A (2) specifies the bulk tariff for IPPs. The fifth set of norm specifies the transmission tariff for POWERGRID, the sole central transmissio company. There is a fair degree of commonality in all the five sets of norms though the are not identical. The effectiveness of all the five sets of norms, in providing incentive for continuous improvements in performance standards, can be questioned. The relevance in the light of changes in the macro environment and the rapid evolution of th Indian Power Industry may also be in doubt. However, it is well established that eac represents an evolutionary stage, which improved the effectiveness of the regulato regime in place at the time that these norms were formulated. It is just as clear th significant adjustments are now required if the positive trend, in evidence since 1948, the evolution of tariff regulation in India is to be maintained.

The legislative changes since 1995 are the next stage in the evolution of power tariff in India. There were three primary changes introduced at that time. First, the constitution of Independent Regulatory Commissions was a major step in the evolution of the process of tariff setting. Second, for the first time the principles of tariff determination were set down in detail in the Act, thus providing a legislative backup to the process of tariff rationalization. Third, for the first time the Act provides a perspective for the future, emphasizing competition, economy, efficiency and equity. We will consider each aspect in detail

The process of independent regulation

The introduction of transparency

The process of tariff determination was traditionally a non-transparent, closed-door exercise. Inadequate data and poor facilities for information collection and dissemination handicapped technical analysis and the use of economic tools. In contrast, the State Commissions, earlier in Orissa and subsequently since May 2000 in Maharashtra, Andhra Pradesh, UP and Gujarat, demonstrated keen interest in making the process transparent by involving stakeholders through a process of dialogue. Towards this end, a number of State Commissions as well as the Central Commission have come out with position papers on different issues concerning the industry, notably on tariff. Some of the Commissions also issued consultation papers on other aspects related to tariff regulation such as cost of capital by CERC and on captive power policy by UPERC.

The universal adoption of the public hearing route by the Commissions is noteworthy because the reform Acts do not make public hearings mandatory. However, the fact that Commissions have the powers of a Civil Court and appeals from their decisions are heard in the High Court may have influenced this trend towards purity of judicial process. It is interesting that India is not unique in this trend. Despite the fact that the Federal Power Act 1935 of the United States specifically exempts hearings in the FERC from the strict judicial process, the trend has been to comply with the due process. The mere exercise of quasi-judicial powers appears to enforce the discipline of the judicial mode of functioning. However Indian regulators have been innovative in their application of the due process. Open house sessions were conducted by the Gujarat Commission where a number of issues, including broader aspects like restructuring etc were discussed. Maharashtra and Uttar Pradesh adopted a very proactive approach of actually reaching out to consumers at six and five locations respectively. An important change brought about by this process is informed decision making made possible by access to data that was earlier not available.

The tariff orders issued by the Commissions have been an important source of this information. The tariff awards issued by all the regulatory commissions are voluminous documents[6] with lot of data and information. Time constraints and lack of experience with the process probably constrained a more participative approach.

Table-1 below summarizes the picture on the process adopted and availability of relevant information in the tariff orders issued by the Commissions.

Table-1: Process and information in the tariff orders

	A.P.	Gujarat	Maharashtra	Orissa	U.P.
Hearings at multiple locations*	✗	✓	✓	✗	✓
Circulation of draft order	✗	✗	✗	✗	✗
Calculation of revenue realized with its components from tariff determined by the Commission for the ensuing financial year	✗	✓	✓	✗	✗
Revenue from existing tariff for the ensuing financial year	✓	✓	✗	✓	✓

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[6] More than 75 pages in all cases, some of them being close to 200 pages.

Calculation and rationale for demand forecast	✗	✓	✓	X
Date of public notice and last date for inviting objections	✓	✓	✓	X
Number of objections received	✓	✓	✓	✓

* In Gujarat, these took form of informal open house sessions.

While the move is in the correct direction, a lot more effort in this direction would be required in the future. Lack of rapport and information along with vested interests hurt by the regulatory decisions, could easily backlash into street agitations et al leading to the danger that independent regulation, instead of being a mechanism to resolve conflict and build consensus ends up as an instrument of triggering social, economic and political conflicts[7]. We recognize here that the regulatory outcomes are invariably affected by a number of constraints, including the informational, transactional and administrative and political constraints, which prevent the regulator from implementing his or her preferred policy[8].

The adoption of an inclusive, participatory process under the independent regulation increases the time taken in decision making. However, the time consuming nature of the judicial process becomes less of a real problem when viewed in the context of actual administrative decision making trends in the past. The history of irregular revision of tariffs indicates that timeliness was not one of the virtues of the pattern of administrative decision making. In Gujarat, for example, the tariff revision has been sporadic and long drawn exercise in the past. The last general tariff revision for consumes supplied at low tension was effected in January 1992 while for those supplied at high tension was effected in May 1993. A further change for industrial consumers and for railways was effected in October 1996. It however appears unrealistic to expect that the time taken for decision making will improve under independent regulation. A quick survey of the international literature reveals that the regulatory process of resetting the tariff takes anywhere between eighteen to twenty-four months and is accompanied by a series of consultations[9]. In the Indian context, Commissions have bound themselves down to ambitious decision making time frames ranging from three to six months. The result has often been that less concern is given to a wider and more active participation by all stakeholders. There is therefore some truth in the statement that the decision making time frames need to be reviewed in the interests of inclusion, adequacy of information and hence more efficient decision making. Table-2 below presents the details in context of the time taken by different commissions to issue the tariff awards. Gujarat is an interesting deviation where, for reasons discussed later, the tariff order could be issued in more than one year but has resulted in a more participative approach whereby extended hearings were conducted and in richness of information contained in the order.

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[7] Prayas Energy Group. February 29, 2000. "Regulators: Walking a tight report." *A Financial Express report*,

[8] Laffont J J and Tirole J. 1994. *A Theory of Incentives in Procurement and Regulation*. Cambridge, Massachusetts: MIT Press.

[9] Energy Regulator OFGEM published its thoughts on the form, scope and duration of revised price contro for electricity grid operator due to come into effect from March 2001. *OFGEM Press release*. March 31, 2000.

Table-2: Comparison of the time taken to release the tariff order

	Date of first submission	**Date of tariff order**	**Time to release tariff order**	**Remarks**
A.P.	December 29, 1999	May 27, 2000	5.0 months	
Gujarat	September 14, 1999	October 10, 2000	13.0 months	
Maharashtra	October 15, 1999	May 5, 2000	6.5 months	
Orissa	August 17, 1999	December 30, 2000	4.5 months	Case No. 12 of 1999
U.P.	Feb 15, 2000	July 27, 2000	5.5 months	Dec 31 submission ignored due to enactment of the Reform Act

Functioning, as they do in an environment of data uncertainty and inadequacy of qualified staff, the process of decision making within Commissions tends to be evolutionary. Specifically, regulators may have one prima facie view at the time a petition is submitted. However, after hearing all parties and in the process, discovering additional data and facts, including frequent and significant amendments to data by the parties, the view of the regulators may change considerably. Frequently, a hitherto unexplored line of analysis and evaluation may open up once the hearings have been completed. The inclusion of these deliberations in the decision risks being termed as violative of the basic principle of the judicial process where all parties must get a chance to debate the evidence on which the judge wishes to rely. There are two options for tackling this problem. Either the additional evidence can be subjected to a hearing process or it can be incorporated into a decision and the decision itself subjected to a hearing. The latter case implies the issue of a draft order on which comments are invited from all parties. This is a departure from the strict requirements of the judicial process. However it has some validity in the context of regulation being intrinsically different from the exercise of judicial powers. The issue of a draft order enables all parties to react to the displayed mind of the Commission and hence point out areas where they feel the decision is not based on facts, errs in analysis or is otherwise bad in law. This may also avoid an unnecessary resort to appeals. Even if the case goes to the appeal stage, the speaking order of the Commission dealing specifically with the public comments on the draft order will provide an easily understood rationale or justification for the order. The decisions taken by Commissions are highly technical in nature, are very quantitative and involve the adoption of economic philosophies. They do not usually revolve only around questions of law or establishment of relevant facts as the judicial decisions. Hence, allowing parties to react to the mind of the Commission seems fair, just and efficient. It is significant that the process adopted by FERC and by the OFGEM both incorporate the stage of a draft order on which parties get an opportunity to comment and not just on the pleadings of the opposite parties. It is obvious that incorporating the stage of a draft order will increase the time taken for disposal. It may also not be necessary for all cases. Non contested cases, or contested cases of a routine nature where the issues are restricted to establishment of facts may not need this additional stage. However in all cases which have characteristics of rule making, where the consequences are to spill over to other cases, where a fundamental principle is being established, the incorporation of a stage of issuing a draft order can be considered as a measure of process reform.

Empowerment of stakeholders

The strength of the judicial process is that it provides a forum for the thorough exchange of information, facts and opinions between all parties. The limitation of the process is tha any asymmetry between the parties in terms of their competence, access to information or ability to utilize the legal provisions of the process will result in skewed results. In the case of public sector utilities in particular the motivation of the managerial cadre representing the utility impacts considerably on the outcome of the case. In the case of small consumer's, poor organizational and representational capacity are similarly limitin factors. This is particularly the case for domestic and agricultural consumers. While som of the States like Gujarat have a long history of strong consumer movement, participati by these bodies in the regulatory proceedings has till now been limited. Designation of an independent public advocate/body to represent the interest before the regulatory agency is a desirable component of the regulatory environment[10]. Some of the Commissions, like Gujarat have initiated this practice.

Independent functioning of the Commission

The fact that regulatory commissions have necessarily to function in an independent manner and not as an arm of the Government, is acquiring general acceptance. However this does not imply a hands off attitude to be adopted by the government. The relationship between the government and the regulator needs to be one of mutual and constructive support in advancing the public interest. The most notable example is that of Andhra Pradesh, where the Commission received strong support from the Chief Minister who actively campaigned against a roll back of the increase in power tariffs announced by the Commission in May 2000. He likened any roll back to virtual disempowerement of the Commission and felt that such an extreme step would send wrong signals to the prospective investors[11]. In direct contrast however, the commission in Gujarat was not able to issue the tariff award for nearly a year because of the lack of support from the Government. The Observer report from Gandhinagar claimed that the Gujarat government held back a hike in power tariff in a move that was prompted by the elections to six municipal corporations as well as district and sub-district councils[12]. The GERC's award, which was to come in mid-April 2000 was delayed till October 2000 and though the Commission firmly denies that it was under any pressure, official sources claim that the ruling party had impressed upon the Commission to announce its award after the election to the municipalities and the panchayats, as it might affect the poll prospects[13]. In the case of Maharashtra the state government intervened negatively in attempting to waive off the electricity dues of the power loom owners of Bhiwandi. This resulted in the MERC having to specifically disallow any special concessions to this consumer class and some resultant tension between the Commission and the government. The State Government in Orissa seems to have adopted a hands off approach of not intervening in the sector. While this approach is convenient for the government, it does not however assist the process of financing the transition. The sudden withdrawal of subsidy, as in Orissa, puts extreme pressure, either on the tariff or on the financial viability of the utility, or both. However, the overall trend is positive, in that governments are by and large giving regulators the space required for rational tariff determination. Our optimism gels from the fact that it is not unusual for regulatory institutions to take time to mature and establish their independence and credibility. The legislative underpinnings are important but not the sole criterion for successful regulation. As significant is the track record of regulators in dealing with difficult decisions that involve substantial interest group controversy[14].

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[10] Joskow P.1998. *Regulatory Priorities for Reforming Infrastructure Sectors in Developing Countries.* Annua Bank Conference on Development Economics, Washington, D.C.

[11] Srinivasan R. August 23, 2000. "Naidu rules out tariff rollback till ERC scrapped." *A Business Standard report* from Hyderabad.

[12] "Gujarat govt puts off power tariff hike." August 15, 2000. *An Observer report* from Gandhinagar.

[13] Desai D. September 13, 2000. "Gujarat in a fix over power sector reforms". *An Indian Express report* from Gandhinagar.

Regulatory capture by interest groups is another source of potential loss of independence of the regulators. US style regulation has strict "sunlight laws" regulating the conduct of regulators as a group and individually in terms of accepting gifts, communing with interested parties or permitting selective access to information. In India the no specific code of conduct for regulators has been created. Regulators follow a system of self discipline in ensuring that their collective and individual conduct is in consonance with the principles of natural justice unbiased quasi-judicial functioning. India has a tradition of symbiotic relation ship between the Public Sector Utilities and Governments. The apprehension is always there that regulators will succumb to a similar relationship. However the record indicates that this has not happened. Regulators have acted independently, against the perceived self interest of public utilities and in favour of the consumers in Orissa, Maharashtra, AP and UP and at the central level. The same is true in the context of the private sector where regulators have attempted to balance the interests of the private sector with that of consumers. Prominent consumer Advocates like Shri Manubhai Shah of CERS (Consumer Education and Research Society), Ahmedabad are not however satisfied at the level of consumer protection afforded by the Commissions. However even he does not deny that the trend is positive and regulatory capture of Commissions by special interest groups has not occurred. The process of independent regulation is far more satisfactory in this regard than that of administrative decision making adopted previously.

Information and technology requirements for efficient regulation

Firms are better off under asymmetric information since it allows for the extraction of rent[15]. It is possible to argue that with most of the regulated agencies still under public ownership[16] managers have little incentive to withhold information since the possible benefits to the utility do not translate into personal benefits for managers. However the fact of withholding information is inherently a passive act and hence easier than the timely provisioning of quality information. Secondly, even public sector managers identi their interest with the firm's interest when it comes to preserving the revenue stream of the utility with no incremental effort.

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[14] Gilbert, R. J., and Newbery D M. 1994 The Dynamic Efficiency of Regulatory Constitutions". *Rand Journal of Economics* 25 (4): 538-54.

[15] Laffont J J and Tirole J. 1994. *A Theory of Incentives in Procurement and Regulation*. Cambridge, Massachusetts: MIT Press.

[16] Except in case of the four distribution companies in Orissa.

As significant a reason for the non-availability of adequate, timely and good quality information is the neglected state of the Accounting and Management Information Systems in general which do not permit the generation of such information. As a consequence, Commissions have regularly waived minimum information requirements as an interim measure pending reorganization within utilities. However the ability to control information flow and to game is a crucial element in affecting regulatory outcomes. Regulatory outcomes can be guided in the desired direction by selective disclosures. Alternatively flooding Commissions with more information than they can absorb can also effectively kill careful analysis of inconvenient facts. Sometimes, when a specific item of information is requested and it is difficult or impossible to delay in providing it, the best tactic is to bury it in a mountain of irrelevant information[17]. There is some truth also in the argument that Commissions may have over specified minimum information requirements far beyond their current capacity for useful analysis. The establishment of a useful data bank, over time, is likely to require refinement of information requirements on the basis of experience. Simultaneously, utilities need to gear up their capacity to collect, collate and provide useful information. The case of NTPC in the Availability Tariff hearings in the CERC illustrates that utilities do not necessarily gain by under providing information. Since the utility was unable to provide detailed data on Station Wise Availability the CERC was forced to work with the inadequate data it was given. The end result has been that NTPC considers the targets for Availability determined by the Commission to be unrealistically high.

Implementation of regulatory orders and decisions

The inadequate capacity of Commissions to implement their decisions is clearly an area of concern. The incapacity of the OERC in inducing rapid improvements in efficiency despite performance linked incentives embedded in the tariff. The travails of the CERC vis a vis POWERGRID and NTPC are all examples of regulators not being able to exercise the considerable formal power available to them under the Act to enforce compliance[18]. Regulatory neglect, which we define as the ability of the utilities to ignore the directives of regulatory bodies without penalty is an observable and retrogressive trend. For example, no action has been initiated till date (October 10, 2000) by the Uttar Pradesh Power Corporation Limited on the direction of the UPERC to approach the Central Electricity Regulatory Commission, within one month of the tariff award issued on July 27, 2000, for determination of tariff for Tanda thermal power plant owned by the

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[17] Owen B and R Braeutigam. 1978. *The Regulation Game: Strategic Use of the Administrative Process.* Cambridge, MA: Ballinger Books.

[18] Section 44 of the ERC Act 1998 empowers the regulators to punish the non-compliance with three month imprisonment or with a fine, which may extend to Rs 100,000, or both. Further, an additional fine of Rs. 4000 per day may be imposed for continuing offence.

National Thermal Power Corporation[19]. Internationally, such negligence of not even requesting the Commission for more time would have drawn a heavy penalty as it is a common practice to impose hefty fines on brigand utilities. We cite here the example of the fine of USD 1.7 million which may be imposed by National Electricity Agency (ANEEL) on Brazilian electric utility FURNAS[20]. The fine would be imposed due to the failure to sign new contracts to buy and sell power as part of an overall regulatory reform within the electricity sector. The utility has already been fined USD 0.9 million for its role in a blackout in March 1999 which left more than half the nation without power for several hours. In the public sector entities, especially in the Indian context where the utilities continue to be in financial loss a penalty may be just another loss without actually making any substantial difference. However, representative penalties may still make some sense from the perspective of sending correct regulatory signals on non-compliance especially for the future.

In summary, the process of independent regulation appears to have vindicated the objectives with which it was installed. The level of transparency has increased with a corresponding increase in the level of participation by stakeholders. Decisions are more inclusive today than they were under the process of administrative decision making. The process is yet far from efficient. Information asymmetries and varying levels of competence across stakeholders restrict the equity and efficiency of the process. Impatience with tardy decision making in the past has imposed impossible time limits on Commissions. Inadequate staffing and analytic capability compounds the fact the information is scarce and of doubtful quality. However these are problems of transition not of direction. The underlying trends in independent regulation are positive. Regulatory Commissions and utilities are starting from fairly low levels of information infrastructure, human resources and managerial incentives. They can only improve.

Principles of tariff determination

Economic regulation is a substitute for the market in situations where the natural monopoly characteristic of industries, as in the case of network utilities, justify such interventions. Regulators are expected to exert pressure on the utility to improve its working to a level at which it would have performed in a competitive market. This model assumes the ability of the regulators to mimic market conditions. Even the partial achievement of such conditions, as demonstrated by experience in U.K, requires substantial effort by the regulatory authorities towards articulating a long-term agenda, defining targets and milestones and designing and implementing the strategy. Where a clear mandate to restructure the market is not available, as in India, pricing strategy is the principal tool available to simulate those conditions.

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[19] Information gathered in telephonic discussion with Mr. J L Bajaj, Chairman UPERC, on September 29, 2000. Further confirmed that no such petition has been filed in a telephonic discussion on September 29, 2000, with Mr. D K Joshi, Deputy Chief (Economics), CERC. In Andhra Pradesh the situation is better with the Commission being more or less satisfied with the steps initiated by the utility. Except on one aspect relating to interest expenditure where the commission had requested for more details, the utility appeared to have more or less satisfied the regulator. Information gathered in telephonic conversation with Mr. N Rao, Secretary, APERC on September 29, 2000. In Maharashtra the commission does not appears to have reviewed the situation because of the appeal for review of the tariff award. Information gathered in telephonic conversation with Mr. Sathpathy, OSD, MERC on September 29, 2000.

[20] "Brazil's FURNAS is fined for March 1999 blackout and may be fined for failing to sign contract." February 2000. *Global Energy Regulation*. NERA.

To achieve the objective of sharing their vision of the electricity sector and specifically o the tariff structures to be adopted to achieve the ends of competition, economy, and efficiency, several Commissions have prepared and issued consultation papers on Tari Principals and Concepts[21]. The papers differ in their style and content however there ar significant areas of agreement and not surprisingly a shared vision for tariff setting in general. Six common themes emerge.

- Clearly the task of balancing the budget of utilities is uppermost. Commissions have emphasized the need for financial viability as a precondition for sustainable growth. This concern is however less significant in the paper produced by CERC, possibly reflecting the satisfactory financial condition of the central government generators and the transmission company. In the case of the state level regulatory commissions however, this concern often overshadows efficiency concerns. The Delhi paper assumes that the utility has no control over power purchase or fuel costs and hence recommends a pass through of such costs. Clearly, this approach is contrary to the need for efficiency improvements and better risk management in the bulk power market. However, a positive aspect of the general concern with financial viability is the consensus view of the need for review of the rate allowed to utilities and the limitations of the existing formulation within schedule VI, which inadequately reflects the business risk and is therefore an inefficient incentive for optimum investments.

- Second, the method to be followed for determination of the Revenue Requirement of the utilities has also drawn considerable interest. The consensus is that for the present the existing Rate of Return method bolstered by elements of Performance Based Ratemaking is the only feasible solution. A gradual movement towards PBR is however indicated by the UP commission.

- Third, the method for allocation of costs to customer classes has drawn attention especially in the context of "social rate setting" or subsidization. The approach here is ambivalent. While there is recognition that subsidy must come explicitly from the government, there is a lack of clarity about the consequences of this not occurring. Should consumers be charged what it costs to supply? What are the efficiency limits of cross subsidization? Is all cross subsidization bad and unsustainable? The AP paper discusses the concept of "capacity to pay". Is this a practical pricing criterion?

- Fourth, the Commissions have focussed on tariff design. Should costs and hence charges be unbundled to reflect the cost of different services subsumed under retail supply? Should Time of Use tariffs be introduced? Can tariffs vary with varying cost of distribution? There is consensus that unbundling is required for restructuring of the sector and the introduction of competition. The limitations are inadequate metering and poor information on consumer profiles. These concerns restrict the development of TOU pricing also which is recognized as being efficient and desirable form the view point of demand management.

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[21] (1) "Conceptual Issues of Electricity Tariff in Orissa" Orissa Electricity Regulatory Commission November 11, 1997, (2) Consultation Paper on Bulk Electricity Tariffs " Central Electricity Regulatory Commission, September 15, 1999, (3) "Issues in Tariff Philosophy" Andhra Pradesh Electricity Regulatory Commission, October 19, 1999, (4) "Issues in Electricity Tariff Setting" Uttar Pradesh Electricity Regulatory Commission, (5) "Concept Paper in Tariff ", Delhi Electricity Regulatory Commission, September 2000.

- Fifth, the need for tariff reform to be accompanied by managerial efficiencies in the utilities and a lowering of the cost of supply is a predominant common concern. The emphasis on improving system losses in the AP, UP and Delhi papers and the emphasis on improving the Plant Load Factor in the UP paper point in this direction. Also significant is the universal demand that governments clarify their social objectives and support such objectives financially through budgetary allocations. It is significant that no paper has expressed a need for government to distance itself form the process of tariff determination. The demand is for direct, though transparent involvement of the government in the process as a stakeholder.

- Six, there is only tacit and indirect recognition that competitive markets provide economically efficient outcomes. The emphasis is very much on improving the "competitiveness" of the utility rather than implementing a time bound plan for the introduction of competition. It is likely therefore that the advantages of competition, which are now well tabulated worldwide will not immediately, be realized in India.

How effective has the process of issuing consultation papers been? Clearly the preparation of a technical paper itself has value in terms of the skill addition and development of a consensual view within the Commission and the dissemination of such learning to other stakeholders. This has been a significant and positive consequence of these papers. Consultation papers should ideally force Commissions to share their views and their vision with the public. This has not occurred very extensively. By and large Commissions have desisted from expressing conclusions and have confined themselves to listing options. Stakeholders can however discern implicit preferences for a certain option. The process has also been hindered by the fact that, barring Orissa, none of the other Commissions have followed up the consultation paper with a definitive paper on tariff incorporating and dealing with the comments received. One notable lacunae has been the failure of Commissions to acknowledge work done by other Commissions. Though these papers are very similar and have been issued over the period 1997 to 2000, none has acknowledged the work done by previous papers. The tendency is to treat every situation as being unique requiring unique solutions. An opportunity has thus been lost to establish consistency in regulatory approach. There is need for a public recognition that Commissions intend to coordinate efforts and processes.

Link between restructuring and tariff reform

We also note here that while electricity industry continues to be regulated almost universally, mainly on the premise of natural monopoly22, major steps have been initiated to restructure the industry. These include California, which recently was at the centre of controversy due to spiraling electricity prices attributed to the pace of restructuring of the industry. It is instructive to present the case of coporatization in New Zealand where the transformation of the New Zealand Electricity Department (also Electricity Division for few years) into the Electricity Corporation of New Zealand (ECNZ a state owned enterprise, created pressures to operate as a commercial organization[23].

Box-1: Corporatization in New Zealand

The corporatisation has resulted in reducing the organizational slack that in the generation and transmissi sectors was estimated to be almost 3 percent of the wholesale prices. It is reported that since corporatisation, there has been considerable progress in reducing costs, particularly by reducing staff numbers, automating, contracting out competitively, and negotiating new fuel contracts over a period of fiv years (1987-92). The main results are summarized below.

a) Wholesale prices have reduced by 8% in real terms.
b) Unit operating costs (excluding fuel and capital related costs) have been reduced by 13% in real terms
c) Sales volumes have increased by 2.6% per annum (in an essentially static economy).
d) Profits have increased from USD 262 million to over USD 400 million.
e) Return on equity has increased from 4% to 12%.
f) Average plant availability increased from 73 to 91% for thermal, and from 87 to 95% for hydro.
g) The number of employees was reduced by about 47%.
h) Productivity as measured by GWh per employee almost doubled from 4.5 to 8.5 GWh per employee.

Table-3 below provides an indication of the approach adopted by the Commissions in the context of attempting to introduce privatization and competition. However, we do not find any concrete timetable and plan for privatization or introduction of private capital. This is not surprising considering that most of the Commissions are not really authorized to deal with issues of restructuring, which continues to be managed within government.

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[22] It is interesting to note that some economists and historians have taken violent exception to the concept of natural monopoly. Horace M Gray is one among these critics

"The public utility status was to be the haven of refuge for all aspiring monopolists who found it too difficult, too costly, or too precarious to secure and maintain monopoly by private action alone. Their future prosperity would be assured if they could induce government to grant them monopoly power and to protect them against interlopers....The obvious conflict between the traditional ideology and the public utility concept was resolved by resort to rationalization. It was said that the enterprises supplying gas, electricity, street transportation, water, and telephonic conversation were 'inherently' or 'naturally' monopolistic; that they had certain 'natural characteristics' which distinguished them from other enterprises.... . that because of this 'natural' force, they tended 'inevitably to become monopolies.... Thus, the fiction of 'natural monopoly' was invented to explain the centripetal tendencies then observable....

Also, Rolf W. Kunneke. 1999. Electricity networks: how 'natural' is the monopoly? *Utilities Policy* 8 (1999) 99-108.

Recent technological trends imply a dramatic change of the network economics, leading to possibilities of inter- and intra- network competition, as well as inter fuel competition..... In general, the natural monopoly character of the electricity network is endangered by three major developments: decentral power generation, the evolution of parallel lines and controlled electricity transport and distribution.

[23] J G Culy, E G Read and B D Wright. 1996. The evolution of New Zealand's electricity supply structure, in *International Comparisons of Electricity Regulation*, Ed. Gilbert and Kahn. Cambridge University Press.

Table-3[24]: Approach adopted on restructuring and privatization*

	A.P.	Gujarat	Maharashtra	U.P.
Restructuring and competition	Noted that the competitive markets lead to economically efficient outcomes and that the goal of the commission was to replicate the competitive environment.	Recommended to the Government of Gujarat that separation of generation, transmission and distribution should be seriously considered	No mention	Noted that competition and privatization were desirable objectives and that the public monopolies have led to inefficiencies
Introduction of private sector	Not mentioned	Not mentioned	Not mentioned	Same as above
Approach on captive power plants**	Not mentioned but has issued a separate paper	Not mentioned	Noted that captive power needs to be encouraged, particularly through cogeneration	Not mentioned but has issued a separate paper

*The restructuring of the sector and privatization of distribution has already been achieved in Orissa.

**The approach on captive power plants can be considered as proxy measure to introduce competition in bulk supply markets

Implementation of tariff strategy

Translation of the tariff concepts elucidated in the consultation papers into strategy has been a complex and challenging job for the regulators because of a number of reasons. Firstly, the extent of under realization of cost on the average requires an average increase of between 30 to 50 percent for the utility to break even at current efficiency levels. Secondly, the impact of this increase has to be borne by those politically sensitive customer classes, like agriculture and domestic, which have been traditionally subsidized. There is little scope for continuing to bleed the industrial sector and large consumers. The tariffs for industry and large consumers have increased over the years far beyond the cost of supply. In most cases, the tariff even exceeds the cost of self-generation and thus provides a perverse incentive for large consumers to abandon grid supply. More significantly, with the overall demand supply imbalance the quality of supply has steadily deteriorated. Voltage and frequency fluctuations are at an extreme level and cause significant though hitherto unquantified loss. Price is a ratio, with money in the numerator and some physical of given or assumed quantity and quality in the denominator and thus price regulation alone is economically meaningless[25] unless indexed to quality. Providing the tariff increase required to balance the budgets of utilities has the nasty implication of taking vested political interests head on. It also is difficult to consider because of the sudden burden it would impose on small consumers. Sharp fluctuations in prices are detrimental to commercial functioning. They can result in deviant consumer behaviour and increase the level of theft. Sharp price hikes can also damage the public credibility of reform in terms of their consumer welfare enhancing impact. Lastly, because of the limitations on the government finances most Commissions can not hope to factor in budgetary support for utilities even as a transition measure.

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[24] Tariff orders as below:

1. Case no 1 of 1999, Retail Tariff of Maharashtra State Electricity Board for 2000/2001 dated May 5, 2000
2. Case No 205 to 207/2000, Tariffs of Transmission Corporation of Andhra Pradesh (APTRANSCO), for 2000/2001 dated May 27, 2000
3. Case No 1 of 1999/2000, Tariff Order 2000/2001, dated July 27, 2000
4. Case No 19 of 1999/2000, Tariff Order, dated October 10, 2000

Despite these limitations it is encouraging that there is a definite move towards aligning the agricultural tariff which traditionally has been the most politicized constituency, with the cost of supply. The average realization from the agricultural consumers in FY 1999-00 was 24.86 paise per kWh as compared to the average cost of supply of 280.88 paise per kWh[26]. It is commonly asserted that such comparisons are not relevant since current realization is an inaccurate estimate and is artificially deflated by the inclusion of theft and other transmission losses, which are not attributable to agriculture. The realization figures may turn out to be higher when corrected for the consumption figures, which are distorted to conceal the high transmission and distribution losses. Secondly, it is also often said that average cost is not a meaningful comparator since agricultural consumers are supplied only during the night hours and hence should pay only the SRMC or the variable cost of supply. Despite the validity of both arguments, the situation remains that the average realization is still far below even the SRMC which, back of the envelope calculation show, is 185 paise per kWh[27]. Hence the move towards bringing agricultural tariffs to costs is welcome. Table-4 below presents the extent of average increase in agricultural tariff in sample states.

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[25] Alfred E. Kahn. 1995. *The Economics of Regulation: Principles and Institutions*. Cambridge, Massachusetts: MIT Press.

[26] Planning Commission. April 2000. *Annual Report on the Working of SEBs &EDs*, Government of India.

[27] The average cost of fuel used in FY 1999-00 was 107.9 paise per kWh, consisting of 102.6 paise per kWh of coal cost and 5.3 paise per kWh of oil cost. Adjusting this by an average loss of 21 percent and adding the O&M cost of 10.6 paise per kWh and establishment and administration cost of 37.7 paise per kWh, the total variable cost works out to 184.9 paise per kWh. All data from Planning Commission. April 2000. *Annual Report on the Working of SEBs &EDs*, Government of India.

Table-4[28]: Increase in agricultural tariff

State	Date of last tariff revision	Date of new tariff order	Nominal Increase in 2000 tariff order	Average increase per year since last revision
Andhra Pradesh	January 1, 1999	May 2000	61 %	43.1 %
Gujarat	June 1, 1993[29]	October 2000	330 %	44.5 %
Maharashtra	September 1, 1998	May 2000	105 %	60.0 %
Uttar Pradesh	January 25, 1999	July 2000	40 %	26.7 %

While the increase in some of the cases, for example in Gujarat and Maharashtra, may look exorbitant, it has to be viewed in a proper perspective of irrationally low existing tariff structure. In Gujarat, for example, the tariff was actually revised downwards in June 1997 and consumers on an average were paying approximately 20 paise per kWh in 1999/00 as compared to 58 paise per kWh in 1986/87. With the revised tariff it is expected that the consumers will pay approximately 98 paise per kWh in 2000/01 as compared to 58 paise in 1986/87, translating into an average increase of less than 4 percent per annum as compared to an increase of 7 percent per annum in the whole sale price index. There has also been substantial increase in the minimum support prices for agricultural commodities during this period. Hence the rationalization of agricultural tariff is a reasonable step and can initiate several benefits, which become viable at higher tariff levels like energy conservation through improvements in the efficiency of water pumps along with water conservation measures.

Tariff design

Efficient tariff design has played a significant role in assisting the process of tariff rationalization. Gujarat has accompanied the stiff tariff increase with an innovative tariff design which incentivises agricultural consumers, to install meters, through a preferential rate for metered supply as compared to unmetered supply. This was done by designing the flat HP based tariff in a manner that it translates into a higher per kWh charge as compared to the metered tariff. Commissions have also simplified the tariff structure, which over the years had becoming increasingly complex with multiple customer classes and slabs. The effort has been to merge the number of customer classes toward the goal of a single tariff for each voltage of supply differentiated principally by the time of supply and if justified on commercial grounds by the density and location of supply. Accordingly the number customer classes and the consumption slabs within each customer class have been rationalized and reduced. Further steps in this direction included merger of a number of additional/surcharges into demand or energy charge appropriately. Fuel surcharge, which used to be an issue of much controversy has also been merged with the energy charge in most of the cases. Table-5 below provides the details regarding rationalization of consumer categories.

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[28] Source: Summary of Tariff Schedules of Electric Power Supply Utilities in India 2000, Council of Power Utilities and Tariff Orders as at footnote 24.

[29] Downward revision in June 1997 has been ignored.

Table-5[30]: Rationalization of tariff structure

Number of tariff categories	**Before**	**After**	**Reduction**
LT			
Maharashtra	8	7	1
Andhra Pradesh	8	8	0
Uttar Pradesh	9	9	0
Orissa			
GRIDCO	Not relevant		
DISTCO'S	7	7	0
Gujarat	11	11	0
HT			
Maharashtra	15	12	3
Andhra Pradesh	6	6	0
Uttar Pradesh	5	3	2
Orissa			
GRIDCO	Not relevant		
DISTCO'S	7	7	0
Gujarat	7	7	0

The level of tariff simplification, which has already occurred, is minimal and considerable scope exists for further rationalization. Commissions have been constrained in this effort by two main factors. Firstly the inadequacy of disaggregated billing data makes customer class wise consumption patterns difficult to assess. Hence rearranging classes and tariff slabs imposes revenue risk for the utility, which is difficult to quantify. Secondly tariff simplification tends to increase the burden of adjustment for currently subsidized customers. With the need to fill the revenue gap already exerting stress on currently subsidized customers Commissions have been rightly cautious in aggravating this problem. Clearly however this is an area where extensive work still remains to be done.

Unbundling retail tariffs by allocating costs to the components of energy service is another exercise which remains relatively unexplored. Customers need to be charged separately for the following services:

1. Bulk power purchase
2. Transmission system costs including transmission loss.
3. Distribution system cost including distribution loss.
4. Retail supply cost including metering, billing, collection and customer servicing.

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[30] Tariff orders as at footnote 24

Under each of the four major cost heads costs can be further sub-classified as fixed or variable and charged for accordingly. Data for cost involved with providing above services for a representative state is presented in table-6 below.

Table-6: Cost of providing different services (Rs./kWh)

Head	Bulk power	Transmission system cost	Distribution and retail supply costs
Total	2.08	0.35	0.97
Fixed	0.68 (33%)	0.24 (69%)	0.62 (64%)
Variable	1.40 (67%)	0.11 (31%)	0.35 (36%)

In comparison most retail tariffs today are single part and do not distinguish between the four separate components of retail supply. Charging these separately has two advantages. First, it forces utilities to account for these costs separately which builds the data base needed in future for unbundling these services. Unbundling is necessary not only to optimize allowable cost through benchmarking under PBR or COS but also is a pre condition for moving to retail choice. Second, unbundling costs focuses the attention of stakeholders on those costs, which they can control. Generally customers have no control over the fixed costs of the utility. They can avoid or reduce only the variable costs. From the regulators perspective, fixed costs are inert costs which can be changed only once at the time that they are incurred and hence can be ignored beyond that stage. What is more vital from the view point of bringing about short run efficiencies are the variable costs which are changeable and hence controllable.

Commissions have devoted considerable effort to redesigning tariff charges. This aspect relates to the allocative efficiency, to which little attention was paid in the past. Allocative efficiency requires the goods to be distributed in a manner that they are received by those who obtain maximum benefit from them, and this can be achieved by relating the prices to the marginal cost. However, the price setting has in the past took no cognizance of the economic theory and the prices have over the years evolved so as to include a heavy dose of cross-subsidy. This has resulted in industrial consumers moving of the grid to self-generation.

The Commissions attempted to correct the historical distortion in the recent set of tariff orders. It was however possible to pay more attention to this aspect as has been paid to the productive efficiency, which requires that electricity is produced at the minimum possible cost. That by limiting the rate of return in itself does not result in efficient allocation is a point brought out very clearly by Shepherd and Gies[31]. The microeconomic theory in contrast to looking at the overall return is interested first and foremost in the determination of individual prices[32]. The optimum amount of total revenues is conceived to be the result of the process that operates in individual markets in fixing prices of individual prices. And as far as question of determination of individual prices is considered, the principle of microeconomics is very clear: prices should be equated to the marginal cost. We however find insufficient recognition of the concept and its application. The regulatory commissions need to be guarded of the tendency, which is evident in US also, where the regulators have been criticized for applying basis other than economic efficiency. Similarly, while some steps towards time of day tariff, reducing the mismatch between fixed liabilities and revenue from demand charges etc. are evident, it was perhaps possible to achieve more. Table-7 below provides a comparative position on steps towards allocative efficiency.

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[31] So whatever the rates of return may actually have been, they cannot by themselves demonstrate whether resource allocation (in and within the utilities) has been efficient. William G Shepherd and Thomas G Gies. 1966. *Utility Regulation: New Directions in Theory and Policy*. Random House, New York.

[32] Alfred E. Kahn. 1995. *The Economics of Regulation: Principles and Institutions*. Cambridge, Massachusetts: MIT Press.

Table-7[33]: Allocative efficiency in tariff setting

	A.P.	Gujarat	Maharashtra	Orissa	U.P.
Application of marginal cost	No mention	No Mention	No Mention	The Commission has moved away from application of marginal cost because of lacunae in database and executing machinery	The Commission has examined the possibility of application of marginal cost through aligning the energy charges with SRMC
Time of day tariff	Not applied	Applicable in the existing tariff structure. The	Introduced for HT industrial	Not applied	A surcharge exists for HT category but it is

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[33] Tariff orders as at footnote 24

		Commission has provided further incentive by substantially increasing the night time concession	consumers. Also noted that it is a critical tool for Demand Side Management		more in form of a charge for making energy available during restricted hours
Reduction of mismatch between fixed liabilities and demand charges	Little progress. No demand charge for domestic or commercial consumers	Noted that it would be practicable to link demand charges with corresponding fixed cost incurred	Observed that it is a desirable objective	No further movement after the second tariff order in 1998.	Some progress. Two part tariff introduced for all categories except unmetered category

Methods of tariff determination

Cost of service approach

Commissions continue to be strongly influenced by by the provisions of Schedule VI of the E(S) Act. This is not surprising considering that the ERC Act and all the state Acts require them to do so and depart from it only for reasons to be recorded in the interests of economy and efficiency. Accordingly, the primary focus of the Commissions so far has been to scrutinize the expenditures and to pare them down to more efficient levels. The revenue requirements were thus reduced, sometimes dramatically on the basis of what was considered reasonable. The Orissa case is a good example. The OERC in its first Tariff order for 1997/98 focussed on the high T&D loss of the utility; GRIDCO. Against an estimated loss of 46.6 percent in the previous year (subsequently said to be under stated) the OERC allowed a T&D loss of only 35 percent. The OERC disallowed 22 percent of the costs projected by the utility on the grounds of high T&D loss and other inefficiencies. In the subsequent year disallowed costs dipped marginally to 18 before increasing to 22 percent in 1999/2000. The MERC, APERC and UPERC have respectively disallowed 9 percent, 7 percent and 14 percent of the projected costs of the utilities[34]. There is some truth in the argument that faced with significant deficits not only in the Test Year but also in the projected period in all utilities, as per Table 8 below, regulators have concentrated primarily on somehow balancing the revenue requirement of the utility with the potential revenue.

Table-8[35]: Revenue deficit (Rs. Crores)

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[34] Ahluwalia Sanjeev.S. "Power Tariff Reform in India" Economic and Political Weekly, Vol XXXV No 38, September 16-22.

[35] Tariff orders as at footnote 24

State	Estimated deficit
Maharashtra	2434
Andhra Pradesh	2917
Uttar Pradesh	2404
Orissa	
GRIDCO	488
DISTCO'S	493
Gujarat	1145

They have also generally assumed a glass ceiling on potential revenue on the basis of a maximum assumed increase in the tariffs of different consumer classes. This ceiling can vary depending on the base level of subsidisation or taxataion for that consumer class, its assumed capacity to pay, its share in total consumption and its political clout.

In this process of balancing future estimated revenues with costs, regulators are focussing on the "reasonableness" of estimated costs. Industry best practice standards are being used to benchmark the allowable costs for utilities. While application of best practice standards is a legitimate objective even under the cost of service (COS) approach of Schedule VI, the only issue is that benchmarks have to be achievable and the time frame for achievement, realistic. The problem with the COS approach is that it does not allow for the formal institution of performance benchmarks well in advance. Costs are allowed or disallowed arbitrarily as a part of tariff reviews. There are no definite price signals in advance, which the utility can react to beyond the general one that costs have to be reduced. More importantly, there is no incentive to reduce costs in advance of the regulator doing so. The utility is not rewarded for unilateral improvements in efficiency. Instead these can become the cause for further contraction of the allowable cost in the next review with the regulator gladly accepting costs where they are low but reducing them where they are high. With a more proactive style of tariff regulation since the onset of independent regulation and hence more frequent and more intensive reviews[36] the perception of regulatory risk amongst utilities has increased.

The Cost of Service approach failed in the pre 1996 period to ensure the financial viability of utilities. This failure was ascribed to the method of its application and political intervention rather than any inherent flaw in its structure. Its use by independent regulators has not changed matters significantly. Utilities continue to be suffer from significant imbalances in the revenue and costs. The Orissa case is a good example because it is the only example where independent regulation has been applied over a period of four years. During this period 1996 to 2000 the total accounts payable, which can be treated as a proxy for the loss, for all the five utilities put together increased from Rs 465.5 crores on April 1, 1996 to Rs 1160.4 crores on March 31, 2000. The alternative is to try the PBR approach or alternatively the Revenue/Price Cap approach.

Performance Based Ratemaking

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[36] The OERC has reviewed the bulk and retail tariff three times since April 1997.

The alternative to the cost-plus approach is the PBR (performance based ratemaking). The PBR approach, while recognizing the revenue requirement of the utility, provides incentives for improving efficiency and reducing costs. It weakens the link between the utility's regulated prices and costs by decreasing the frequency of rate cases and/or by employing external measures of cost[37]. The control aspects of regulation are thus sought to be replaced with a system of incentives and penalties through institution of industry wide norms. As a result, the PBR creates incentives, which are similar to those that would exist in a competitive market place. Such a system would reward efficient management while inefficient ones would sooner or later be thrown out. PBR also eliminates the tendency of utilities under the cost plus regulation to be more capital intensive, known as the *Averch-Johnson effect*, than they would be in competitive environment.

International experience in regulatory reform and implementation of PBR schemes suggest that significant efficiencies in investment are possible. Productivity in the UK electric power industry has increased from around GBP 40,000 per employee in 1980 to GBP 170,000 in 1998 in constant 1995 prices[38]. In India also the adoption of the PBR approach has worked extremely well in the case of NTPC. In 1992, as a result of the work done by the K.P.Rao Committee, operational cost norms were specified by the Government of India under section 43 A (2) of the E(S) Act for National Thermal Power Corporation (NTPC). These norms specified the heat rate, auxiliary consumption rate and the schedule for recovery of the capacity charge comprising Rate of Return on equity and Operations and Maintenance expenses linked to achievement of the Plant Load Factor/Availability of the unit. Achievement in excess of the cost norms is retained by NTPC while all costs incurred above the cost norm are borne by NTPC. The norms were valid for five years. During this period, the NTPC's profit before tax (PBT) grew by over 28 percent per annum from Rs 735 crores in FY 1991-92 to Rs. 4195 crores in FY 1998-99. Similarly the ratio of PBT to net assets grew from 6.1percent to 26.4 percent. The norms are still to be revised by the Central Electricity Regulatory Commission, to whom the jurisdiction of regulating the tariff of central generators was transferred in May 1999.

There is also clear evidence of the fact that the Commissions are not only aware of the advantages of PBR over COS but are actively adopting it. The UP commission benchmarked the administrative and overhead costs of the utility to the national average as a target and on that basis reduced the allowable expenditure. It similarly compared the performance of the generation segment with the national performance benchmarks and found it severely lower. In Maharashtra, the Commission has required the utility to reduce the cost of power purchase using the merit order principle. In Orissa, the Commission has been innovative in linking efficiency gains beyond the target level prescribed by it to a corresponding increase in the return earned by the utility thus providing a powerful incentive for performance well in advance in the best traditions of PBR. These are stray instances however inadequate data, the lack of a historical perspective and relative unfamiliarity with PBR have restrained regulators from a more complete and formal adoption of PBR. In Maharashtra, for example, the Commission approved the Operation and Maintenance expenditure of Rs. 675 crores as requested b the MSEB. This translates into 16.22 paise per kWh as compared to the national average of 10.60 paise per kWh and 8.63 paise per kWh in Gujarat, which is a comparable utility[39]. Requiring the MSEB to operate at the national average would have resulted in a saving of nearly Rs. 239 crores. This illustrates that the Commission has not rigorously adopted the principle of PBR. Had it done so, it would have needed to establish performance benchmarks for all major cost heads. In view of the relative inefficient levels of operations, it is conceivable that such benchmarks would need to be projected several years in advance so as to bring in efficiency improvements over time and give an opportunity to the utility to adjust to the new efficiency levels.

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[37] G A Comnes, S Stoft, N Greene and L J Hill. November 1995. *Performance-Based Ratemaking for electric Utilities. Review of Plans and Analysis of Economic and Resource Planning Issues, Vol I.* U S Department of Energy.

[38] Electricity Industry Review" January 2000, Electricity Association Services Limited, London

What are the advantages in formally adopting a PBR approach? First, since the PBR schemes generally have a longer duration, typically of upto five years, the regulatory ris emerging from reviews is reduced. In the Indian context, infrequent reviews with annua performance parameters announced in advance, eliminates the problem of political interference. Second, since performance parameters are determined on the basis of industry wide norms and not the costs and performance standards of any individual utility, the potential for realizing rent due to information asymmetry is reduced. Infrequent tariff reviews also free the government and the regulators to focus on other tasks including improving the quality of supply, enforcing tighter customer service standards, grievance handling and the sustainable development of the electric supply industry. These are important tasks, which are vital for the sustainable implementation of reforms. In the current context these get neglected since the entire attention gets focussed on tariff determination which is an annual exercise. If tariff rationalization is to be delinked from reform, restructuring and privatisation, efficiency improvements and improvements in the quality if service provided to consumers are necessary. This becomes difficult when then the limited capacity of the Commissions is devoted extensively to tariff determination. Often regulators may need a longer time interval between rate reviews to develop the analytical capacity to prepare for the next review. Regulators may use such longer time interval to publish consultation papers and review the results of the associated hearings so that tariff reviews do not happen in a vacuum of uncertainty. The reduction of regulatory risk is an important precondition to privatisation[40]. The adoption o PBR will assist in this process. PBR also provides advance signals which efficient utilities can use to optimize operations. The longer interval between tariff reviews also assists in preserving the benefits of efficiency enhancement within the company. Under COS, there is always a risk that the benefits of efficiency improvements will be passed throug to consumers. Hence both PBR and the Revenue Cap/Price Cap approach are more conducive to efficiency enhancements than COS.

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[39] Planning Commission. April 2000. *Annual Report on the Working of SEBs &EDs*, Government of India.

[40] Vijay Chawla. August 4, 2000. New tariff puts KESCO privatisation in peril. *A Business Standard Report* from Kanpur.

The new power purchase rate, fixed by the UP power regulatory commission, has jeopardized the privatisation chances of the Kanpur Electricity Supply Company (KESCO). At Rs. 2.15 per unit power purchase rate, KESCO will be incurring a loss of Rs. 174.53 crore per annum.

The design of a PBR plan involves an assessment of the behavioural pattern that is sought to be encouraged or discouraged as also the defining the allocation of risks between the customers and the investors. The objectives that the programme is supposed to achieve should be defined as clearly as possible at the outset. In India, the possible regulatory goals can be to provide powerful incentives for cost reduction, improving the quality of supply and service, to encourage efficiency in use and to promote use of renewable and alternative forms of electricity. It is often useful to do a comparison of the PBR scheme with the existing cost plus regulation and define how the PBR mechanisms would more effective in achieving the sought objectives.

The second important dimension of the PBR plan is its term. The firm, during the term of the plan has an opportunity to take advantages from the efficiency enhancement investments. The longer the term of the plan, the stronger the incentives for such investments. If the term is too short, utilities become subject to *ratchet effect*[41], under which they will not even try to make a cost-effective investment because they may not recoup their productivity-improving investment and will have to try harder in the future just to break even[42]. It is interesting to note that the idea of long term plans actually traces its history to the regulatory lags under cost plus regulation. Vogelsang and Finsinger have demonstrated that basing a firm's allowable prices in one year on its cost in the previous year could provide the firm with the incentive to adopt a pattern of prices that converged to the efficient level[43].

Regulatory commitment to the plan and selection of appropriate indices for benchmarking performance are also important criteria. The PBR plans also often include mechanisms for sharing earnings with the ratepayers. While the economic theory prescribes that the utility's best incentive to efficiency enhancing investments is to retain all of the incremental earnings, the regulatory commissions as well as a number of experts[44] have argued and preferred sharing of above the benchmark earnings with the ratepayers. Allowance for unforeseen circumstances (commonly known as the Z factor), events or cost items which may outside the utility's management control, is another typical characteristic of the PBR plans. The important criteria for approving the Z factors should be a clear understanding of the risks that the regulator wants the utility to bear and these may or may not necessarily be items that are outside of their control. Thus, while the economic theory prescribes that the risks should be allocated in a manner that they are borne by those who are best placed to bear it and although certain risks may be beyond the managements control, they nevertheless fall right within the range of risks that businesses in competitive markets must bear and hence the managements should, therefore, be charged with managing the exposure to such risks through investment decisions and cost controls[45]. This argument provides an interesting twist to the inclusion or a promise for inclusion of fuel adjustment clause in most of the reform acts and subsequently the tariff awards. Since the fuel adjustment clause allows recovery of every additional rupee spent on the fuel, they provide the utility with a zero cost insurance policy. They also create disincentives for investing in fuel efficient and renewable technologies as also for operating the units efficiently.

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[41] Laffont J J and Tirole J. 1994. *A Theory of Incentives in Procurement and Regulation.* Cambridge, Massachusetts: MIT Press. "The rent extraction concern gives rise to the celebrated ratchet effect. The regulator infers from a high performance an ability to repeat a similar performance in future and becomes more demanding. Consequently the firm has an incentive to keep a low profile".

[42] G A Comnes, S Stoft, N Greene and L J Hill. November 1995. *Performance-Based Ratemaking for electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues, Vol I.* U S Department of Energy.

[43] Vogelsang and J Finsinger. 1979. Regulatory Adjustment Process for Optimal Pricing by Multiproduct Monopoly Firms. *Bell Journal of Economics* 10 (1) 157-71.

[44] Marcus W B and D M Grueneich. 1994. *Performance-Based Ratemaking: Principles and Design Issues.* San Francisco, CA: Energy Foundation.

Further, there are certain pitfalls that the regulators need to guide against in designing the PBR schemes. Under the PBR scheme, the firm will have a tendency to increase the profits by reducing the quality of service and hence inclusion of penalty clauses on appropriate service quality parameters is desirable. In U K for example, the violation of service quality standards often results in payments directly to the affected customers thereby providing sufficient incentives for maintaining or infact improving the quality of service. It is thus incumbent on the regulatory commissions to keep a constant track on the service quality and devise penalty that is sufficiently high to retain the managerial attention. The PBR schemes are also associated with being non-equitable to the consumers. These concerns arise because of the above markets returned associated with PBR, fewer opportunities to air grievances/litigate against the tariff and because it leads towards Ramsey prices which are often perceived as unfair by the commissions[46]. It is critical to ensure good quality database to implement successful PBR schemes and it should also be noted that PBR schemes also require significant regulatory input and oversight though the focus of attention is to ensure maintenance of quality rather than judging the prudence of expenditure.

The application of PBR to whole sale tariffs, particularly for central government owned generators, has been continuing for a decade now. The need of the hour is to formalize the demise of COS regulation and its replacement by a hybrid of PBR and Price Cap regulation. All ERC have already adopted an informal Price Cap regulation in the case of industrial tariff which have been increased only by the rate of inflation or less. This move should be formalized and extended to all customer classes which are currently "taxed". These customers should know that over the next five to ten years their tariffs would decline in real terms. Instituting a RPI minus X type of formula applicable for atleast five years for these customers will induce certainty and allow such customers the freedom to plan ahead. Declining tariffs will also reduce the incentive for self generation and thus pull industrial customers back into the grid. Price Cap regulation can also be used to contain the tariff shock from the withdrawal of subsidy. Price Caps, possibly corresponding to the capacity of a consumer class to pay or the marginal value added by incremental use of electricity, should be notified as efficient limits for tariff increase over time. The notification of such caps will serve a dual purpose. First it will allow governments to justify the provision of subsidy for the customer class. where there is a danger of the cap being breached. It will also facilitate the budgeting of subsidy in a medium term perspective. Secondly, it will also guide the ERC in tariff setting. The uniform adoption of Price Cap regulation in a more general way will have to await stabilization of the system. Secondly, the usefulness of Price Caps to meet large increases in capacity is somewhat uncertain. The incremental capacity requirements of the system can best be met under PBR, which allows a somewhat higher level of collaboration between the ERC and the utility.

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[45] The Regulatory Assistance Project. *Best Practices Guide: Implementing Power Sector Reforms.* The Energy Group, Institute of International Education for Office of Energy, Environment and Technology (EET), USAID.

[46] G A Comnes, S Stoft, N Greene and L J Hill. November 1995. *Performance-Based Ratemaking for electric Utilities: Review of Plans and Analysis of Economic and Resource Planning Issues, Vol I.* U S Department of Energy.

The adoption of PBR is a fitting replacement for the Cost of Service methodology of tariff setting. Its application, so far, has been sporadic, selective and inconsistent. The results have, not surprisingly, been lopsided. PBR has been applied to areas like T&D loss reduction, where the intention is to squeeze utility profits. However other areas, where operational costs have reduced, continue to be regulated under Cost of Service thus depriving the utility of efficiency enhancements in these areas. Regulatory Commissions need to formally adopt PBR through the notification of appropriate tariff regulations, which will establish the cost, and performance standards against which utility Revenue Requirements are to be tested. This is essential if the gains from efficiency enhancement are to accrue in a timely fashion during the process of transition. The transition to fiscal stability of the electric power system is a period of severe financial stress. Hence a combination of PBR and Price Cap regulation appears to meet the needs of the transition far better than the traditional Cost of Service Regulation. Its demise need cause us no discomfort.

Conclusions

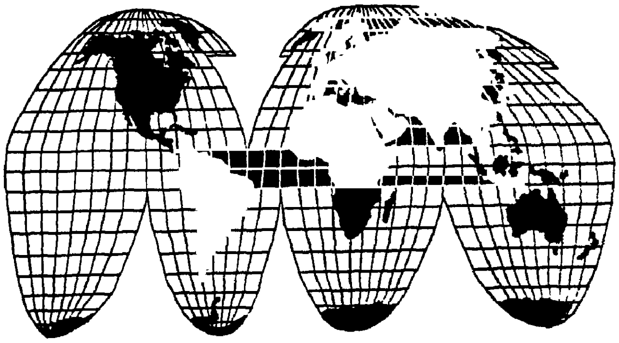
Restoring the financial viability of utilities has been the focus of measures of tariff reform initiated in 1998 (1996 in Orissa) via the Electricity Regulatory Commissions Act 1998 and in the State Reform Acts. Including the central level, thirteen commissions are functional which cover over two thirds of the power supply. Of these, six, including the CERC, have issued tariff orders apart from initiating other regulatory proceedings. Other Commissions have not yet issued tariff orders though other proceedings have been held. The process adopted for the conduct of their proceedings has uniformly conformed to the judicial pattern thus ensuring transparency, fairness and equity. There have been some innovations like informal hearings and a proactive approach to siting the hearings by taking them close to the petitioners. In several cases, the strict rules of evidence have also been relaxed, keeping in view the expense involved in adhering to these rules and with a view to allow for wider participation. However no Commission has so far adopted the standard practice prevalent in the US and in the UK of exposing the mind of the Commission and seeking comments on the views of the Commission prior to finalizing the order. The restraint seems to be apprehensions that this will increase the time for disposal of petitions, that it may be unnecessarily dilatory and that it does not fit well with the exercise of judicial powers. Commissions have also been restrained in promoting the inclusiveness of hearings and actively encouraging participation by stakeholders and by the tight time schedules prescribed for decision making. In general however the process adopted under independent regulation has changed the scope and the range of participation by stakeholders in tariff determination. The process of tariff setting has become inclusive, the level of technical analysis has improved which has reflected positively on the quality of the decision making in this regard.

Commissions have a difficult task in implementing tariff reform. With extreme levels of tariff distortion, uncertain political support, withdrawal of subsidies by governments from hitherto beneficiary public utilities and the continuing uncertainty of industry restructuring the degrees of freedom available for Commissions to implement tariff reform strategies are limited. It is praiseworthy that Commissions have responded with a blend of technica sophistication and restraint in addressing this problem. Without formally departing from the framework of cost of service tariff determination elements of the Performance Based Ratemaking have been introduced thus bolstering administrative fiat with economic incentives. The utility response to such economic incentives has not been assessed so far except in the case of Orissa. In Orissa there is hope that the private owners who hav now been in operation for over an year now would respond more proactively to economi incentives than the publicly owned utility did previously.

Tariff reform will work well where the government continues to support the process financially. It will be more efficient where there is a private utility in place to respond to the economic incentives devised by regulators. It will succeed where regulators resist the temptation of revising tariffs frequently or in tightly controlling the utility's profits. Tariff reform will be more efficient where regulators are assured functional independence, adequate competent staff and facilities. The legislation has already provided the basis for successful independent regulation and tariff reform. The key is in devising an implementation strategy that ensures the continued active participation of all stakeholders. So long as public utilities are service providers, a major part of the tariff reform effort lies with governments. Unless public utility management is improved and the cost of supply aligned to efficient levels, regulators will be constrained to continue to disallow costs, thus perpetuating the financial crisis, which they were expected to reverse. Regulators can never be efficient managers. They can only create the enabling environment within which efficient managers can function. In the absence of such mangers the efficacy of independent regulation is diluted. It is upto governments to bring the process of industry restructuring to a logical conclusion by privatizing utilities. The experience in Orissa, Maharashtra, AP, UP and Gujarat has shown that poor management skills, inadequate managerial incentives, non responsive management, lack of public accountability and the continued lack of autonomy in public utilities are significant barriers to the financial viability of the electric supply industry in India. These are challenges that independent regulation is not mandated to meet.

Energy and Mining Sector Board

The California Power Crisis: Lessons for Developing Countries



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Foreword

The U.S. electric power industry, the last major energy industry in that country subject to traditional utility regulation, is being opened up to widespread competition. Some states allow their retail electricity customers to choose their electricity supplier. Competitive trading of wholesale electricity and the emergence of independent grid operators have spread to many regions of the United States. The number of independent power producers and marketers competing in the U.S. retail and wholesale power markets has increased substantially over the past few years.

However, these new markets have not emerged without problems. California introduced competition to its retail and wholesale power markets in 1998, but has experienced a major crisis during 2000 and into 2001. This crisis has provoked a major debate about the risks, as well as the rewards, of deregulating power markets to allow competition. In fact, the California power crisis is giving deregulation a bad name, both in the United States and beyond to other countries that are reforming their power sectors.

This characterization is somewhat misplaced, however, since the California reform is more precisely characterized as part deregulation and part re-regulation. Nevertheless, some observers argue that the California experiment with deregulation should be scrapped, while others argue that the deregulation is still a worthwhile endeavor to make the electric power industry more efficient and customer-oriented, and that problems such as California's can be solved by adjusting market rules. A third group argues that California's power crisis is a failure of market design rather than a failure of deregulation.

Deregulation of power markets would be rejected on false grounds if the causes of the California crisis were largely specific to the design of the California reform. In view of this uncertainty, the World Bank has a duty to its clients and itself to gain an understanding of what has happened in California, and to draw lessons from the California experience that are applicable to other countries. The purpose of this paper is to fulfill this duty. In so doing, the paper also assesses whether the crisis could have been avoided through better market design and management. Overall, the paper concludes that much of the crisis was avoidable. Nevertheless, the paper also identifies many invaluable lessons for other countries that are considering or implementing power sector reform, and I herewith commend it to all who are involved in this endeavor.

JAMAL SAGHIR

Director, Energy and Water
Chairman of Energy and Mining Sector
Board

Acronyms

CPUC	California Public Utilities Commission
CTC	competitive transition charge
FERC	Federal Energy Regulatory Commission
IOU	investor-owned utility
IPP	independent power producer
LADWP	Los Angeles Department of Water and Power
NOx	nitrogen oxides
PG&E	Pacific Gas & Electric
PPA	power-purchase agreement
PURPA	Public Utilities Regulatory and Policy Act
QF	qualifying facility
RECLAIM	Regional Clean Air Incentives Market
RMR	Reliability Must Run
RTC	retail emissions credit
SCAQMD	South Coast Air Quality Management District of California
SC	scheduling coordinator
SCE	Southern California Edison
SDG&E	San Diego Gas and Electric
SMUD	Sacramento Municipal Utility Department
TOU	time-of-use
UDC	utility distribution company

Units of Measurement

GWh	gigawatt-hour
MW	megawatt
MWh	megawatt-hour
TCF	thousand cubic feet

Introduction

> "California's new electricity market ended up being designed in a highly politicized process.... [W]hat emerged was the most complicated electricity market ever created.."
> —Professor Paul Joskow , *The New York Times*, January 13, 2001

> "This is a dreadful mess for a state that is held up around the world as a model of innovation...."
> —*The Economist*, January 20, 2001, p.57

> "Its problems are largely manmade."
> —*Newsweek Magazine*, April 3, 2001, p. 23

The California power crisis is so sudden and serious that it is prompting policymakers in many countries as well as other U.S. states to look for lessons that can be applied to the reform of their own power sectors. Concerned policymakers around the world are asking: If things can go so badly wrong with a reform that did not involve wholesale privatization of the electricity supply industry in such a rich and sophisticated economy, what are the implications for much less well-endowed countries embarking on the full menu of reform including privatization?

When a power sector reform like California's fails, political authorities are inevitably under strong pressure to "do something" to solve the crisis. In a recent special session of the California legislature called by the governor, legislators introduced more than 75 bills intended to solve one or more aspects of the crisis. Unfortunately, quick-fix "solutions" often lead to outcomes that can be inconsistent with the original reform objectives and can produce outcomes that are even worse than the conditions that triggered the reform. For example, at the time of this writing (March 2001), the California and federal governments have proposed or undertaken actions including the following:

- *Price caps*. The Federal Energy Regulatory Commission (FERC) imposed price caps that may deter the investment needed to overcome the current supply shortage.
- *Forced sales*. The U.S. Secretary of Energy issued several orders that required generators and natural gas suppliers to continue selling to non-creditworthy California buyers.
- *Government energy trader*. A new state law authorizes the state government to spend up to $10 billion on the state's credit to purchase wholesale electricity that can be resold to the three large privately owned utilities.
- *"Nationalization" of the grid*. The State of California may become the new owner of the portion of the high-voltage transmission grid currently owned by the three large privately owned utilities.
- *"Balkanization" of wholesale electricity trade*. The state's Assembly has passed a bill that would make it difficult to export electricity produced from new generating plants located in California to buyers outside the state.

Many elements of the California reform package are peculiar to a complicated and unusual market design that was the outcome of a political compromise reached by various stakeholder groups. Many of these features will have no immediate, or even near-term, relevance for most developing countries. Since this paper has been written mainly for power sector officials in developing countries, it focuses selectively on the substantive lessons of the California crisis that pertain to the design of power sector reform in these countries.

In developing countries, the California power crisis may be creating the impression that power reform is too risky. **The power crisis in California does not justify this**

conclusion. For many developing countries, the *status quo* in the power sector is the riskiest alternative of all. The *status quo* often creates a drag on economic growth through inadequate and poor-quality power supply. In addition, limited government funds are frequently diverted to the power sector that would otherwise be available for schools, clinics and roads. Therefore, most countries simply have no alternative to a substantial and basic reform of the sector that almost always requires restructuring and privatization. But like all human endeavors, power sector reform can be done well or done poorly. The principal lesson of California is that good intentions are not enough. Any reform must pay close attention to starting points, the particular problems that need to be solved, and the appropriateness of the path selected for solving these problems.

The paper is organized into three parts. It begins with an overview of the key features of the 1998 California power sector reform: how it differs from reforms elsewhere, the events and actions that have put it in a crisis mode, and the main lessons that can be learned from the crisis.

Following the overview, the main text is divided into two parts. Part I discusses in depth the lessons learned, which concern mainly the establishment and regulation of a mandatory, wholesale power market based on spot pricing. Since this is not a near-term option for many developing countries, the paper also describes other, more-limited forms of competition that may suit their situations. Although privatization was *not* an element of California's reform, the state's experience does indirectly provide important lessons for the privatization and regulation of distribution enterprises and new market entities in developing countries.

Part II details the specific reforms initiated in California, reviews the factors that led to the crisis, and examines whether the crisis could have been avoided through better market design and management. The paper draws on numerous sources such as published articles, reports and websites, as well as the working experience of World Bank staff in numerous countries.

Overview of the California Reform and its Lessons

Why the Reform?

California's economy in the early 1990s. Major statewide recession. High unemployment. Loss of industry and jobs to other states. The state's governor believed that continued high electricity prices (about 50 percent higher than the U.S. national average in 1996) would drive many industries out of the state.

Pre-reform electricity sector

- Three-fourths of the state's consumption was supplied by three large vertically, privately owned utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E). The rest of the state was served by large and small municipal utilities.
- High electricity prices were caused by expensive nuclear power and green power. Specifically, massive cost overruns on two major nuclear power plants and statemandated purchases of power from independent power producers (IPPs) using renewable and other technologies at prices significantly higher than the costs of traditional technologies.
- There was surplus generating capacity just prior to the reform (April 1998).
- Approximately 20 percent of California's electricity supply was imported from neighboring states.
- The three privately owned utilities were regulated by the California Public Utilities Commission (CPUC) under a traditional U.S.-style cost-of-service regulatory system with some targeted incentive mechanisms. The CPUC described the existing regulatory system as "fragmented, outdated, arcane and unjustifiably complex."

- *Expectation.* The new market system would lower prices by encouraging competition among existing and new wholesale and retail suppliers and by reducing regulation.

The Nature of the Reform

Key Features

- The three privately owned utilities were "encouraged" to sell off their generating plants but without any vesting contracts to buy back the output of plants.
- In return, the utilities were allowed to recover their "stranded costs" (i.e., anticipated above-market costs) associated with the two high-cost nuclear power plants and the state-mandated purchases of power from certain IPPs through a "competitive transition charge" on consumers' electricity bills.
- The state government mandated a 10-percent reduction in retail rates. Retail rates were frozen for four years or until stranded costs were recovered. Actual consumer bills went down little because the reduction in rates was largely offset by the competitive transition charge.
- Retail (residential, commercial and industrial) customers were given the right to choose alternative electricity suppliers.
- A non-profit, independent system operator (Cal ISO) was created to operate the transmission facilities owned by the private utilities (about 75 percent of the state's high-voltage grid). The Cal ISO

also operated a bid-based real-time energy market as well as several other markets to acquire grid support services (i.e., ancillary services).

A separate Power Exchange (Cal PX) was created to operate a bid-based, centralized market for forward (day-ahead and day-of) power sales. The two largest private utilities were required to buy and sell all of their electricity through the Cal PX.

Both the Cal ISO and Cal PX were governed by large boards, each of which was made up of more than 30 stakeholder and non-stakeholder members.

The retail electricity rates of individual privately owned utilities continued to be regulated by the CPUC. Even though the Cal PX and Cal ISO were under the regulatory jurisdiction of FERC (the national electricity regulator), the CPUC and the state government had substantial de facto influence over their actions. The two regulatory entities, the CPUC and FERC, sometimes issued conflicting orders.

- The coverage of the reform was incomplete. Municipal utilities were given the option of not participating in these new arrangements. In general, they chose not to participate.

How the California Reform Differs from Other Power Sector Reforms

- Initially, the major private distribution companies were not allowed to buy outside of the spot markets. (No vesting or forward contracting was allowed.) Hence, they were totally exposed to the price volatility of the Cal PX spot markets.
- Distribution companies and others who serve retail customers were not required to own or have under contract sufficient generation capacity to meet their peak demands.
- No provision was made for passthrough of wholesale purchase power costs to retail rates until full recovery of stranded costs or March 2002 (whichever came first).
- The complicated design involved multiple, sequential wholesale markets operated by two new separate entities (the Cal PX and the Cal ISO). In other U.S. regions, the ISO and PX are combined in a single entity.

The Reform Process

- The reform operated by "political consensus." The final version of the reform package reflected a compromise among competing stakeholders. It was incorporated in a bill that was passed unanimously by the California legislature.
- Criticisms of the final design by outside power sector reform experts were generally ignored by state and national political and regulatory authorities.

The Crisis

- The highly contentious siting and permitting process for new generating plants blocked the installation of any major new generating plants for more than 10 years. California's installed generating capacity declined by about 1,200 MW between 1997 and 2000.
- Wholesale markets operated by the Cal PX and Cal ISO worked reasonably well for the first two years (1996–98) while the initial surplus of generating capacity disappeared. Less than 2 percent of residential customers exercised their option to pick new electricity suppliers because

new suppliers could not offer substantial reductions in consumers' electricity bills under the rate freeze and competitive transition charge during the reform transition period.

- A shift in market fundamentals occurred: large increases in electricity demand in California and neighboring states, reduced availability of hydropower in California and the Pacific Northwest, and big increases in the prices of gas and pollution permits to emit nitrogen oxides (NOx).

Wholesale spot prices skyrocketed starting in the spring of 2000. California utilities paid around $11 billion more for electricity in the summer of 2000 than in the summer of 1999. Similar wholesale price increases in neighboring states had less impact because, unlike California, only 5 to 10 percent of their overall supplies are purchased on the spot market.

Mandated rolling blackouts throughout the state since December 2000 seriously disrupted the state economy (the sixth largest in the world). Even more widespread blackouts are expected in the upcoming summer.

Some evidence indicates that the growing shortage of generating capacity, combined with certain features of the complex wholesale market design, may have allowed some generators to exercise market power.

Limited or no pass-through of wholesale costs to retail customers has forced the two largest private companies to incur around $12 billion in unfunded liabilities since April 2000. They are on the verge of bankruptcy.

The Cal PX ceased to operate its two markets on January 31, 2001.

The Lessons

Overall Design of the Power Market

- A poorly designed power market will not operate properly, and inadequate attempts or delays in correcting market distortions will spill over into a serious financial crisis.
- The California power reform crisis offers many valuable lessons on "what not to do" for reformers of power sectors, particularly for the establishment and regulation of a mandatory, wholesale power market based on spot pricing.
- The California experience indirectly provides important lessons for the privatization and regulation of distribution enterprises and new market entities in developing countries, even though privatization was not an element of California's reform.
- The California experience also provides a lesson about crisis management: there is no way out that is quick, painless or cheap. "Quick-fix" solutions to basic design flaws usually fail and may aggravate the problems. Any real solutions will impose heavy costs on stakeholders such as suppliers, consumers, shareholders, and legislators.

Requirements for Competition to Work in the Wholesale Power Market

- Spot markets for wholesale power require careful design of market rules and price regulation to allow participants to manage their trading risks efficiently.
- Competition requires adequate capacity to meet demand without experiencing supply constraints (generation, transmission, fuel, etc.). The market must provide signals and incentives for investment in new generating capacity

when needed. These can be provided by various means, such as imposing a capacity obligation on distribution companies purchasing power in the market, setting up a parallel capacity market to the energy spot market, or developing a forward energy trading market whose prices signal expectations about future supply/demand balances.

- Competition requires that investors in new supply capacity face no major barriers to entry to the wholesale power market. These barriers include uncertainty and expense in facing delays to the permitting process, regulatory uncertainty about after-the-fact price reviews, and regulatory constraints on managing trading risks efficiently by means such as hedging instruments.
- The design of a competitive power market is too complex and delicate to be dominated by heavy political compromises that are intended to shield stakeholders from the consequences of the reform. Market design should be firmly guided by sound economic principles.
- New competitive trading arrangements in a wholesale power market should be introduced carefully to provide scope for dealing with design flaws as well as settling-in problems.

Introducing Competition to the Wholesale Power Market

- Most developing countries should start with limited forms of competition that can evolve to full wholesale competition through spot markets once the sector can manage full competition without uncontrollable market power. The creation of bid-based spot markets should generally not be their top priority.
- A mandated, deregulated, wholesale bid-based spot market should be pursued only if certain conditions are likely to be satisfied. Some of these prerequisites are also required for other, more limited forms of competition. But the consequences of not satisfying these conditions are most dramatic and harmful in a mandated and deregulated spot market.
- Price-based spot markets are generally too risky for small-to-medium–sized power systems because of these systems will lack sufficient bidders to maintain effective competition.
- Cost-based spot markets, such as those developed in Latin America, offer a simpler and less risky alternative that can yield competitive benefits for medium-sized power systems, complemented by imposing a capacity obligation on distribution companies.
- Likewise, it is simpler and less risky to impose obligations on generators and distributors to provide ancillary services (i.e., grid support services) as a condition for being connected to the grid, rather than trying to synchronize one or more separate markets for ancillary services with an untested spot energy market.
- Vesting contracts should be allowed as a form of insurance for distributors purchasing from a new spot market. A vesting contract that fixes the sale price for trade between existing or new generators and distributors for five or more years should be established before the market goes into operation. They also provide at least initial protection against market power.
- The spot market can evolve from a cost-based to a price-based system as the power market becomes more competitive.
- Alternative trading arrangements to spot markets, such as bilateral trading among

multiple buyers and multiple sellers, should be considered for small power systems and as transitional arrangements until the benefits of a spot market are considered to outweigh the risks.

- Bilateral trading becomes unsustainable as the only trading method when the complexity of balancing system supply with demand in real time becomes unmanageable as the number of buyers and sellers increase. Commercial transactions cannot be divorced from physical realities of power system operation.
- A temporary single-buyer arrangement can be considered—but with strong reservations—in situations where bilateral trading or spot markets need substantial time for development of power purchasers and sellers.

Introducing Competition to the Retail Power Market

- Retail tariffs should be aligned with the costs of wholesale power. Regulators should avoid rate freezes that expose distributors to the possibility of an unsustainable squeeze on their cash flow occurring when rising wholesale power costs approach or even exceed fixed retail rates.
- Regulators should encourage and even require suppliers to allow large users to adjust their demand for power in real time, through smart metering and other means, since competition works properly only when both suppliers and users interact in the market (i.e., prices must be seen by both the demand and supply sides of the market).
- Interruptible supply tariffs work only when consumers do not expect to be called more than occasionally to reduce their demand on the power system. Power outages are enormously costly for consumers who have already adjusted to using grid power. Hence blackouts are symptomatic of enormous macroeconomic losses. This shows in turn the potential gains from reforming systems in such a way that such a *situation* is avoided.
- Small retail power users should have the option of avoiding exposure to the high price volatility that can occur in spot markets for power. Power suppliers or other entities should be given regulatory scope to absorb this volatility through risk management techniques.
- One or more commercially viable entities must have a legal obligation to provide adequate supplies for consumers who prefer to deal with a default supplier rather than shop around in the market for a supplier.
- In countries where the power supply industry is under state ownership and is due to be privatized and opened up to competition, stranded costs for past investments by utilities need not be recovered through surcharges on consumers' bills. This is because these costs will generally be absorbed by the state through the proceeds received from the sale of these assets.
- Full retail competition should be saved for last. In countries that have not achieved substantial household electrification, it will generally be more productive to focus on encouraging competition to serve those who do not currently have access to electricity, than on retail competition for those who already have access.

Regulating Power Markets

- The economic regulatory system must be open, independent, credible and not prone to bankrupting reasonably efficient firms.

- Regulatory "certainty" for power purchases by distributors is of no value if, as in California, it can lead to bankruptcy of efficient firms. The regulatory system must be designed to allow the cost of power purchases that are beyond the control of a distributor (e.g., mandated purchases in the spot market, assigned purchases under a vesting contract or purchases under a previously reviewed bulk supply tariff) to be automatically passed through in retail tariffs.
- If there is a spot market, the regulator should encourage hedging by allowing distribution entities to recover hedging costs if hedging opportunities are available (rather than forbid it until it is too late, as in California).
- The governance of the system operator should be kept independent of the market participants. Independence can be achieved directly by prohibiting market participants from having an ownership interest in the system operator and requiring that the system operator's governing board be composed of nonmarket participants (i.e., nonstakeholders). Governance boards composed of stakeholders should not be too large or dominated by one or more classes of market participants.
- Price caps should be used only as a last resort, since they introduce distortions with unintended consequences and do not correct the causes of the problem that they address.
- The system operator should monitor markets carefully and continuously for signs of trouble—such as unusual price movements that may indicate abuse of market power—and give the system operator the authority to penalize those who violate market rules.
- An independent and expert market surveillance group should be created outside of the system operator. It should issue periodic public reports assessing the state of the market and mobilize quickly when a problem arises. The members of the group must be perceived as independent and objective.
- Regulation of fuel and power markets should be coordinated, especially the linkage between electricity and natural gas markets when most new generating plant burns natural gas.
- In large countries it is important to divide regulatory responsibilities rationally between national and state regulators to avoid unnecessary conflicts. It is not enough to simply say, as in India, that electricity is a "concurrent subject" with regulation shared by national and state regulatory authorities. The nature of the "sharing" has to be defined precisely to avoid costly and distracting conflicts.
- The economic regulator for the power sector and the environmental regulator need to work together. Each is in a position to undermine the work of the other. The ultimate success of both regulators requires a change in their mindsets. The power regulator has to accept that compliance with strict environmental standards is an integral element of power sector reform. The environment regulator must recognize the need to work constructively with developers of new generating plants to help achieve compliance with agreed-upon environmental standards.

Part I

Lessons from California or What the Power Minister Needs to Know

1. Start with limited forms of competition that can evolve to full wholesale competition.

Competition is intended to produce operational and investment efficiencies. Alternative forms of competition exist that are less complex than the mandated, centralized competition model adopted in California. These alternatives can be implemented separately or in combination. None of these alternatives precludes moving to a deregulated, bid-based spot market in the future.

1.1 Cost-Based Spot Markets with Obligations for Capacity and Ancillary Services

If participation in a competitive wholesale market is mandated, then a less risky alternative is to begin with cost-based bidding (as in four Latin American countries and in New England until recently, and as proposed for Ghana) rather than price-based bidding (as in California, Colombia, El Salvador and the United Kingdom).

A cost-based spot market based on generators' actual or estimated variable production costs is easier to establish and provides more protection against market power than a bid-based spot market. It represents a relatively natural extension from the traditional merit-order dispatch systems used in many pre-reform, vertically integrated power systems. While the cost-based bid market determines day-to-day dispatch patterns, there is usually a parallel "free" market in which generators, distributors and others can enter into hedging contracts to lock in future prices and revenues. After several years of operational experience, the cost-based spot market can evolve into a bid-based spot market. The three principal advantages of a cost-based market or pool are that it

1. Ensures efficient dispatch (if generators tell the truth about their production costs),
2. Makes it difficult for generators to exercise market power, and
3. Is easier to implement because it builds on what the system or grid operator was doing prior to the reform.

North Americans and Europeans often consider the Latin American cost-based approach to spot markets an inferior form of competition. But the reality is that it has worked even if it does not fit a textbook definition of perfect competition. Those countries that have adopted this approach in Latin America have generally experienced significant increases in private investment combined with clear improvements in operating efficiency.

The designers of the reform should consider imposing two types of obligations:

- *A capacity obligation on distribution enterprises and other load-serving entities to avoid complete reliance on a new short-term market to induce investments in new generation capacity.* This requirement—currently in effect in Eastern United States, Texas and several Latin American countries—means that anyone who sells electricity to retail customers must also have enough generation capacity (either owned or under contract) to meet customer demands. An alternative, used in Chile and Argentina, is to require that the pool or system operator acquire capacity from generators on behalf of those who buy from the pool using administratively determined capacity payments that are in addition to the pool price. These two approaches would work in either a cost-based or a bid-based spot market. Only California appears to have introduced a mandatory spot market without any accompanying capacity obligation or capacity payment mechanism.

- *Initial obligations on generators and distributors to provide ancillary services (i.e., grid support services) as a condition for being connected to the grid.* As practiced in Latin America, England and Wales, this is generally easier than trying to synchronize one or more separate markets for ancillary services with an untested spot energy market. Once the basic energy market is functioning well, it may be less costly to acquire ancillary services through market mechanisms.

1.2 Multiple Buyers, Multiple Sellers in Bilateral Markets

Pools that operate a mandatory spot market, whether bid- or cost-based, are one form of a multi-buyer, multi-seller market. There is, however, an alternative form of a multi-buyer, multi-seller market that does not require creating a pool. This alternative allows distributors, large industrials or both to buy directly from generators and other suppliers through one-on-one bilaterally negotiated transactions. The bilateral transactions could be for short-, intermediate- or long-term supplies. It has been suggested that this type of market would be easier to implement in developing countries because it would be voluntary and does not require the complicated protocols or software of a mandatory spot market.

Such voluntary markets involving one-on-one bilateral transactions have existed for many years in the United States and continental Europe. One big difference, however, is that the buyers and sellers were usually vertically integrated utilities with sufficient generating capacity to meet all of their energy needs. In general, these traditional vertically integrated utilities participated in these markets to "fine-tune" their supply needs (i.e., to lower their supply costs in certain hours rather than to meet their basic supply needs).

The question then is whether this type of market is feasible in a different type of industry structure. Specifically, is it a viable option in an unbundled power sector (separate enterprises for generation, transmission, system operation, distribution and retail supply) in which buyers would have little or no supply of their own and therefore would have to rely on the market for most or all of their supply needs? Moreover, would it work in a developing country where there is simply not enough generating capacity to meet the demands of all connected customers?

Because developing countries lack experience with this type of market, there are no clear-cut answers. One major concern, however, is the issue of "balancing." Even if a distribution company is able to contract for all of its expected needs, its moment-to-moment demand will rarely be exactly equal to the amount for which it has contracted. Therefore, there has to be some balancing mechanism. (This balancing problem does not occur when the trading is among vertically integrated enterprises because buyers will have their own generation supplies as well as the technical capacity to self-balance.) If the balancing mechanism is an organized market with more than a few generators and distributors, the cost and complexity of setting up this residual balancing market may be almost the same as a full, mandatory spot market.

One possible, less costly alternative to an organized balancing market would for distributors to acquire most of their needs through one or more supply contracts with generators, and then hire a generation company or the system operator to be responsible for meeting the moment-to-moment fluctuations in its demand. Under this approach, the balancing would be performed by the hired agent rather than by a balancing market.

Regardless of whether the underlying industry structure is bundled or unbundled, it appears that voluntary bilateral markets are feasible only if there is (1) little congestion on the grid (i.e., ample transmission capacity), (2) a small number of buyers and sellers and (3) an independent operator who has complete knowledge and effective operating control of the entire interconnected grid. This type of market may not be workable once the number of buyers and sellers rises above a threshold level because it becomes increasingly difficult to match a group of bilaterally negotiated power-sales agreements of varying durations. These agreements produce hard-to-predict physical demands on the grid, requiring a grid operator to balance the overall supply and demand of electricity on a moment-to-moment basis.

Allowing industrial customers to participate in such markets raises other concerns. If industrial customers have been subsidizing residential and other customers (which is the case in many countries), the industrial customers will no longer be a source of cross-subsidies if they can buy from other suppliers. This, in turn, may lead to the need for a big immediate increase in retail tariffs for non-industrial customers, rather than a series of phased-in increases over a longer period of time that could be managed by phasing the exodus of non-industrial customers from the market.

It is not enough to simply provide distribution companies with the opportunity to participate in such a market. Distribution companies must also be given incentives to be efficient and intelligent buyers. In particular, the regulatory system must include explicit incentives that allow distribution companies to earn higher profits if they find more economical supply sources.

1.3 Single-Buyer Model

The single-buyer model requires that all generation supplies be procured by an entity specifically mandated to fulfill this function, and that this entity in turn be the only seller of bulk power to distributors and large users of power.

This is the "toe in the water" approach to introducing competition. In principle, it is the most limited form of competition because it allows competition only for one-time competitive procurements for relatively well-defined products—the supply of base, intermediate or peaking power for a specified period of time. In practice, however, it is often poorly implemented because the single-buyer entity is usually an existing state-owned power enterprise that is not a skilled buyer and that may be forced into signing high-priced and poorly designed power-purchase agreements (PPAs) through political or commercial pressure exerted by its government owners. Furthermore, it carries a substantial risk that the political and commercial interests that benefit from this approach will block further reform by ensuring that it remains in force.

Although single buyers tend to be state-owned enterprises, state-owned entities usually have limited experience in purchasing power, and this lack of experience may put the future budget revenues of their governments at considerable risk. This could be the case in California, where an existing state agency has become the *de facto* buyer for about 50 percent of the short- and long-term supply needs of the three privately owned utilities. This happened because generators in California and neighboring states were no longer willing to sell to these three companies, which account for about 75 percent of California's retail sales, because the three companies could no longer pay for their power purchases. But simply replacing these companies with a state-controlled single buyer will clearly not be a solution if the three utilities are not allowed to charge tariffs to their retail customers that are high enough to allow them to pay for the power that they will now purchase from the state agency. Almost exactly the same situation exists in the Indian state of Orissa, which, like California, was the first state in its country to undertake significant reform. The four privately-owned distribution companies in Orissa are unable to pay for the power purchased by the state-owned single buyer because their retail tariffs have been set too low.

Because the single-buyer model in developing countries often postpones an essential element of reform (i.e., raising retail prices to cover costs), it frequently forces governments to offer backup payment guarantees they usually can't afford because ultimate consumers are "insulated" (at least temporarily) from bulk power costs. However, what consumers do not initially pay for in electricity rates, they (and those who do not have access to electricity) will eventually pay for in higher taxes or in the reduction of other government services (e.g., hospitals, roads and schools) that are "crowded out" because of the subsidies or guarantees that now go to the electricity sector. In California it has been reported that a state government surplus of several billion dollars will soon be exhausted because of the need to cover power purchases by the state buying agent. Standard & Poor's, a U.S. credit rating agency, put the state on a credit watch "with negative implications" when the state began to purchase power.

Countries with small power systems may be tempted to consider adopting a single-buyer model because unbundling generation and distribution into a number of small entities, combined with sophisticated market mechanisms, may not be a realistic option for such systems. In the more than 100 countries with installed capacity of less than 1,000 MW, the potential number of operators and distributors in the bulk supply market may simply be too small to support workable, ongoing competition unless the country has strong interconnections to neighboring countries. Moreover, trying to introduce sophisticated trading arrangements could divert attention from other higher priorities, such increasing supply, reducing losses and providing electric power to those who are currently unserved.

Other options besides the single-buyer model exist for purchasing wholesale power in small power systems. One approach worth considering is a "joint action agency." This is a common model used by groups of small power systems in several parts of the United States, including California (e.g., the Northern California Power Agency). A joint action agency is essentially a buying cooperative made up of small distribution systems that pool their demands and hire purchasing expertise. It is different from the pure single-buyer model in two important respects. First, the buying cooperative is an entity created and governed by the buyers rather than a separate, government entity that is not accountable to its customers (the current norm in many developing countries). Second, it is voluntary. If a small distribution system believes that it can do better job by purchasing on its own, it always has the option of "going off on its own" as long as it satisfies its previous purchase commitments.

2. Move to a full bid-based spot market only once the necessary conditions are in place.

A full bid-based spot market provides helpful price signals needed by consumers and potential investors when the necessary conditions are in place. It is *not*, however, the highest reform priority in a power sector that is starting from a base of pervasive underpricing, significant cross-subsidies, overstaffing, high technical and commercial losses and widespread political interference. The danger of trying to create such a spot market too soon in the reform process is that the effort required to make it work properly will divert attention and resources from trying to solve more fundamental problems. It is a potentially time-consuming distraction when more basic problems need to be addressed.

A mandated, deregulated, and bid-based spot market should be pursued only if certain conditions are likely to be satisfied. Some of these prerequisites are also required for other, more-limited forms of competition. But the consequences of *not* satisfying these conditions will not be as dramatic or as harmful as they would be in a mandated and deregulated spot market. The conditions include the following:

- Market power is not pervasive. There are sufficient non-affiliated suppliers in each segment of the system load curve, no serious bottlenecks exist in the transmission system, and control of fuel supply is not under the control a major generator. This condition is unlikely to be fulfilled in a country with a small power system and few interconnections with power systems in neighboring countries.
- Distributors have the money to pay for their power purchases and distribution costs (i.e., retail tariffs are cost reflective and are not artificially suppressed for political reasons). Competitive power markets will fail unless distribution entities and other buyers are commercially solvent. California started with commercially viable distribution entities but then pushed them towards bankruptcy by forcing them to buy in a spot market in which prices skyrocketed and the regulatory system (which was the result of a political compromise) prevented the two largest distributors from passing these high bulk-power costs through to their retail customers.
- Buyers and sellers in a deregulated market have the means and incentive to hedge price volatility in forward spot markets, through intermediate and long-term contracts, etc., and are not forced to rely completely on mandatory, short-term bulk power markets. Apart from vesting contracts (see below), volatility in spot electricity prices can be hedged with a variety of other financial instruments such as futures contracts, options and derivatives. The market for such instruments are not easy to create, can be manipulated if there is not enough volume and, more importantly, may divert attention from more critical "first order" tasks such as raising tariffs so that distribution entities can recover their total cost.
- There are few bottlenecks on the transmission system that would block transactions and create segmented markets. If there are bottlenecks, a workable and efficient system exists for pricing congestion. For example, transactions in a day-ahead or hourly energy market should not be arranged

in isolation from whatever congestion exists on the grid.

- The market and system operator are genuinely independent in ownership and decision-making from market participants (generators, distributors, retail and wholesale suppliers and final customers). The governance system in California resembled a mini-legislature and was susceptible to deadlocks.
- New generation and transmission capacity can be built without excessive delays in permitting and siting (i.e., supply can respond to market prices). In California, the susceptibility of the siting and permitting process to legal challenges by nearby residents was a major barrier to entry for new generators. In developing countries, similar delays could be caused by weak environmental agencies that are administering cumbersome administrative processes.
- Retail tariffs are designed so that at least large- and medium-sized customers can "see" spot market prices on an hourly basis and can cut their consumption in response to high prices (i.e., demand can respond to high prices). Consumers cannot "respond" to a price that they cannot see. California distribution companies are now pursuing a crash effort to install real-time meters and tariffs for their large customers before summer 2001.
- Sufficient time, money and human resources are available to develop the new market system. A fully developed, bid-based spot market system involving multiple sellers and buyers requires significant expenditure on real-time metering, bidding protocols, settlement and market-making software and communication and data transmission equipment. Much of these costs are independent of the size of the power market. California is a rich state, so it was able to finance a veritable army of consultants working under extremely tight deadlines to install the necessary hardware, develop the protocols and write the corresponding software. In contrast, most developing countries will not have these resources. And even if they did, these limited resources would produce bigger and more immediate benefits if used in extending service to unserved households, putting in retail meters where such meters don't exist and making transmission and distribution investments to improve the basic quality of current service.
- There is a "workout" of high-priced power purchase agreements with IPPs or an explicit stranded-cost mechanism in place before the market becomes operational. A wholesale market will generally not work unless this happens.

Policymakers sometimes fail to appreciate that it is more difficult to create a bid-based spot market in electricity than in other energy commodities because of the basic physical realities of electricity production and consumption:

- Electricity is very expensive to store.
- It is subject to rapid changes in demand.
- There are pervasive externalities on the grid. For example, physical failure at one location can cause the collapse of the entire grid supply.
- Its demand and supply must be balanced on a moment-to-moment basis.

- The demand for electricity (on a real-time basis) can be very unresponsive to price increases.

3. Allow vesting contracts as a form of insurance for distributors purchasing from a new spot market.

Before the market goes into operation, the government or its privatization agency should establish a vesting contract that fixes the sale price for trade between existing or new generators and distributors for five or more years. (The same technique, which is sometimes described as "allocated PPAs," can also be used when new distribution entities are created even in the absence of an accompanying spot market.) Vesting contracts provide "insurance" in case the market design is flawed, and they provide revenue and cost certainty to generators and distributors in the early years of reform. In most countries that have created short-term markets, vesting and other hedging instruments may cover as much as 80 to 90 percent of total power trade. This was not the case in California, however. The largest distributors were required to sell generating plants and were not allowed to repurchase the output of these plants using vesting contracts. Instead, they were required to purchase almost all of their supply needs in the newly created spot market. This is the functional equivalent of requiring that everyone buy their airplane tickets for a particular flight in a mandatory auction that takes place 30 minutes before the scheduled departure.

However, vesting contracts are not risk-free for distribution companies. If the contract prices are high because of corruption or a non-competitive or poorly negotiated procurement process, future distribution companies and their customers may not be able to pay the high prices. In such cases, a vesting contract will simply perpetuate a bad outcome and lead to "stranded costs" when and if competition is introduced. Starting power sector reform with a legacy of high-priced PPAs is like starting a race with a 20-kilogram weight on each leg.

Vesting contracts can also be used with the creation of separate distribution entities through privatization or divestiture, even if these actions are not accompanied by the creation of a spot electricity market. Such contracts reduce uncertainty for potential investors in both distribution and generation. They also allow the regulator to focus in the early post-privatization years on distribution costs and performance (e.g., wires' costs, technical and non-technical losses, billing and collections) that are under the more direct control of distribution entities.

Vesting contracts are a transition mechanism. When the contracts expire or when the distribution companies make additional power purchases, the regulator will need to establish a system to ensure that the distribution entity purchases economically to protect its captive retail customers. And the regulatory system must provide incentives for distribution companies to enter into a portfolio of purchase contracts to continue to hedge price risks.

4. Save full retail competition for last.

Retail competition did not succeed in California for several reasons relating to the specific design features (e.g., a 10-percent mandated rate reduction combined with a rate freeze, the recovery of stranded costs through a competitive transition charge) of the California retail competition program. But even if California had been successful in introducing retail competition, this does not imply that most developing countries should make retail competition an early action in their reform programs.

Full retail competition (i.e., allowing every retail customer the right to pick their electricity supplier over an existing distribution network) is expensive and complicated to implement. In England and Wales, it has been estimated that the initial hardware (metering, data transfer and telecommunications systems) and software has cost more than US$1 billion so far.

It appears that other countries (Australia and Norway) and other U.S. states (Pennsylvania) have had more success with full retail competition than California. But it also important to remember that these countries, like California, are starting with full household electrification.

In countries that have not achieved substantial household electrification, it will generally be more productive to focus on encouraging competition to serve those who do not currently have access to electricity, rather than on retail competition for those who already have access. For example, in poor, rural areas, the competition may be for the right to receive a government subsidy (whether it is for capital, operating costs or both) in return for an obligation to provide a specified level of grid or off-grid service (Argentina and Chile). In other countries, privately or cooperatively owned mini-grids with an accompanying generating unit (i.e., a mini-privatization) in rural areas can be encouraged if regulatory licensing requirements are kept to a minimum and the mini-grid providers are allowed to offer electrical service with lower quality-of-service standards than the main grid distribution companies. If the mini-grid operator wants the option of being connected to the main grid for enhanced reliability, then the key regulatory issue is the terms and conditions of the backup service that is provided to it by the main grid distribution company or a separate generation company. The general rule is that the regulator should not impose regulatory requirements above and beyond the willingness and ability of people to pay.

Policymakers should also consider adopting a simpler version of retail competition—by tying the energy prices paid by residential customers to a measure of market prices paid by industrial customers who have access to competing suppliers. This "piggy-backed" form of retail competition should be easier and less costly to implement than full retail competition. A variant of this approach has been adopted in Chile.

5. Starting points matter.

The starting conditions in power sectors vary enormously among reforming countries. The "starting points" are particularly important in four areas:

1. *Prices.* Are retail power prices above or below costs? In California, the pre-reform prices were high, but in many developing countries the prices are too low to recover costs. It is virtually impossible to undertake any serious power sector reform (including the creation of ongoing bulk power markets) unless a government is politically committed to closing the revenue-cost gap as its first priority.
2. *Capacity.* Is generation capacity adequate to meet the demand in the power market? In California, the reform started with a cushion of excess capacity, while many developing countries have a shortage of capacity. Is there potentially enough within-country generation capacity (assuming weak interconnections to other countries) to make it worth thinking about a national bulk power market? In Africa, among the 34 sub-Saharan countries that each have less than 1,000 MW of installed capacity, spot markets and other forms of ongoing bulk power

competition, while interesting to read about, are largely irrelevant to their immediate problems (unreliable service, high losses and insufficient generating capacity).

3. *Coverage.* Is there full electrification? California has full electrification coverage. In many developing countries in Asia, Africa and Latin America, large segments of the population lack access to electricity. For example, of the 34 countries of sub-Sahara Africa, more than 90 percent of the countries have less than 20 percent household electrification.
4. *Institutions.* Will investors and consumers trust regulatory and government institutions to honor commitments and treat them fairly? In California, the state and national regulators have existed for more than 60 years and have established a good track record of honoring their commitments. In many developing countries, the regulator is a new institution, its responsibilities vis-à-vis the government may not be clear, and previous governments may have a history of reneging on agreements. In effect, there is often an "institution gap" as well as a "supply gap."

The reform transition strategy should reflect starting conditions and country characteristics. For example, in a country starting with suppressed prices (i.e., prices that are less than costs) and a shortage of supply, there is a greater political risk to introducing deregulated bulk power competition than in another country that starts with cost-reflective prices and a surplus of supply. Similarly, it makes little sense to try to create a deregulated bulk power market in a small country with weak interconnections to neighboring countries. The better strategy is to privatize what already exists, provide subsidies for rural electrification and strengthen interconnections to neighboring countries (Central America) before contemplating a deregulated, bulk power market.

Basically, it makes little sense to start a power sector reform without first deciding which problems need to be solved. If a country moves too quickly to a complex bulk power market that is inappropriate to its current problems, it runs the risk of losing what may be a "once-in-a-generation" chance to make fundamental reforms in its power sector. Power sector reform is a highly political process. Policymakers need to be alert to the fact that the necessary political support will quickly disappear unless the reforms produce "early wins" that are readily discernible to the general public.

6. The economic regulatory system must be open, independent, credible and not prone to bankrupting reasonably efficient firms.

Independent regulatory commissions are necessary but not sufficient for sustainable power sector reform. It matters little to investors that a regulatory commission is "independent" if the commission issues tariff decisions that make it difficult or impossible for a reasonably efficient distribution company to recover its total costs (purchase power plus wires costs).

6.1 Distribution

Multi-Year Tariffs

Most developing countries that have successfully privatized distribution have given potential investors reasonable certainty about the initial revenue stream for 5 to 8 years through a multi-year tariff formula that is fixed in the law or a concession agreement (akin to a contract between the government and the investors). Because this tariff-setting system is usually an integral and legally binding element of the overall privatization package, the regulator may have very little to do with setting tariffs in the initial post-privatization period. This has been the norm in Bolivia, Chile, El Salvador, Georgia, Guatemala, Moldova and Peru.

Multi-year tariffs are the regulatory equivalent of going on "autopilot." Although they reduce risk for investors (and have been adopted in almost every country that has successfully privatized distribution), they may be difficult to implement if there is considerable uncertainty about the initial levels of cost, consumption and losses and the level of investment needed in meters, lines, transformers and substations to raise service to acceptable standards. A multi-year tariff that turns out to be too generous to new private companies also runs the risk of a political backlash that could lead to after-the-fact windfall profit taxes or even re-nationalization. Consequently, it may make sense in some countries to combine a multi-year tariff with a profit- and loss-sharing mechanism outside of a pre-specified dead band. Such a sharing mechanism increases the political sustainability of the reform.

Any multi-year tariff should also be combined with performance standards so consumers can experience some improvements in service to balance the pain of tariffs that are initially likely to be higher. However, the performance benchmarks must be developed with considerable care. In particular, any benchmarks must (1) take account of starting points (e.g., technical and non-technical losses on the system), (2) recognize that not all customers may want or can afford the same levels of quality, (3) be able to be objectively measured and (4) be bounded with respect to their financial impact on the enterprise.

Purchased Power

Like regulatory "independence," regulatory "certainty" is of no value if, as in California, it can lead to bankruptcy of efficient firms. For distribution companies, it is especially important that the regulatory system must be designed to allow for the automatic pass-through to retail tariffs of purchase power costs that are beyond the control of the distributor (e.g., mandated purchases in the spot market, assigned purchases under a vesting contract or purchases under a previously reviewed bulk supply tariff). Where the distributor has some discretion in its purchases (e.g., post-privatization purchases for incremental demand growth), the regulatory system should create incentives for the distribution company to minimize its purchase power costs. It appears that such incentives did not exist in California. The privately owned utilities were generally reluctant to pursue potentially cost-reducing, long-term purchases in 1999 for fear that the purchases would be found "imprudent" in a later, after-the-fact regulatory review.

Incentives to Hedge

If there is a spot market, the regulator should accommodate hedging by allowing distribution entities to recover hedging costs if hedging opportunities are available (rather than forbid it until it is too late, as in California). There needs to be a balance in the regulatory system. The regulator should not write a blank check by accepting all hedging costs, nor should the regulator discourage distributors from hedging because they fear disallowance of profits under after-the-fact "prudency" reviews. The better approach would be to establish before-the-fact price benchmarks for wholesale power purchases to encourage efficient buying. The indexed purchasing power benchmarks created by the electricity regulators in Northern Ireland, Scotland and the Netherlands are useful models. The choice of benchmarks is critical. Several Latin American countries have adopted an index based on six-month estimates of nodal prices as the purchased power benchmark. However, they have found that the distribution companies will simply rely on their legal right to buy all of their power needs at these prices and not attempt to engage in any hedging transactions.

Blaming the Regulator

A politician can do few things more unpopular than raising electricity tariffs. The Governor of California was quoted as saying that he could have solved the crisis in "20 minutes" if he had been willing to raise retail tariffs. Although political authorities in developing countries are often initially nervous in allowing the creation of "independent" regulatory commissions, they frequently discover the political convenience of attributing necessary but unpopular tariff increases to the independence of their regulatory commissions. The principal benefit is the ability to say that the tariff increases are beyond one's control. For example, when the California Public Utilities Commission announced average retail tariff increases of 40 percent, on top of an earlier 10 percent increase, the Governor was quoted as saying: "I can't order or direct an independent body. I've not given any advice to them on the subject of a rate increase." (*Washington Post*, March 27, 2001, p. A2)

6.2 *Market Regulation and Monitoring*

Governance of System Operators

The governance of the system operator should be kept independent of the market participants. Independence can be achieved directly by prohibiting market participants from having an ownership interest in the system operator and requiring that the system operator's governing board be composed of non-market participants (i.e., non-stakeholders). But it may not always be possible or desirable to create a non-stakeholder board in some developing countries. Therefore, the alternative is to create a stakeholder board where no entity or class can dominate board decisions. The failure of the California stakeholder board suggests four lessons:

1. The board cannot be too large or it will be ineffective as a decision making body. (The California system operator board had 25 voting members before the Federal electricity regulator dissolved it.)
2. The voting rules must ensure that one or two classes cannot control the board's decisions.
3. The regulator must be able to step in and make a decision if the board is deadlocked.
4. Consumer representatives or advocates should be viewed as market participants.

Price Caps

Once a market has been created, price caps should be used only as a last resort if serious structural or market design flaws emerge. When prices go up, the natural instinct of most political authorities is to impose price caps. But price caps distort markets, and they treat symptoms rather than causes. If the underlying problem is a shortage of generation capacity, a price cap will not help with the two needed solutions: increasing supply and restraining demand. As the former FERC chairman observed: "We cannot 'price cap' California out of a supply shortage."

With any price cap, there is always a danger that it will be set too low. For example, it appears that the price caps imposed in California were at times below the (historically high) variable production costs of some old generating units, and so prevented these units from operating profitably when the system needed their output. If price caps are put into place, they should be applied comprehensively across all markets in which a generator might sell. If they are imposed piecemeal, generators will simply sell in other markets where the price is not capped at all or capped at a higher level (as happened in California), thus defeating the purpose of the caps. Price caps must be a temporary, last-resort measure. If they are kept in place for too long, they will reduce the pressure to deal with the underlying problems and will ultimately prevent the market from developing as originally planned (as happened with the wholesale electricity market in the Ukraine).

Monitoring by System Operators

Regulators should require the system operator to monitor markets carefully and continuously for signs of trouble—such as unusual price movements that indicate abuse of market power—and give the system operator the authority to penalize those who violate market rules. The system operator has detailed knowledge of daily operations and therefore is in a unique position to serve as the regulator's "eyes and ears." In California, several (but not all) of the recommendations made by the Cal ISO's monitoring unit, as well as an external monitoring unit (see below), were adopted by regulators.

Monitoring by Outsiders

An independent and expert market-surveillance group should be created. It should issue periodic public reports assessing the state of the market and mobilize quickly when a problem arises. The members of the group must be perceived as independent and objective. A small- or medium-sized country might have to hire experts from outside the country because most knowledgeable people within the country will be perceived, at least initially, as being biased because of past connections with the industry. The surveillance group must have a broad mandate. It should be charged with assessing not only the performance of the market, but also the actions of the system operator and the regulator. (For example, in California the market surveillance group has concluded that the "soft price cap" imposed by the FERC would probably worsen the existing supply shortage.) Finally, the market surveillance group should work with the system operator but must have the clear right to issue reports without the prior approval of the system operator.

Self-Regulation

Where organized spot or balancing markets are created, industry "self-regulation" of the accompanying grid and commercial codes should be encouraged. In California, these technical advisory groups were able to make some technical improvements in grid and market operation. The regulator need not formally approve every decision or arbitrate every dispute, but the regulator must have the legal right to intervene on its own initiative or in the event of a formal complaint by a market participant.

Regulation of Fuel and Power Markets

Regulators must coordinate the regulation of fuel and power markets—especially the linkage between electricity and natural gas markets when most new generating plant burns natural gas. For example, if a generator is owned by or affiliated with a company that provides natural gas transportation to competing generators, this corporate relationship could be used to put its competitors at a competitive disadvantage.

6.3 Division of Authority between National and State Regulators

In large countries (e.g., Argentina, India, Brazil, Canada, China, Russia and the United States), it is important to divide regulatory responsibilities rationally between the national and state regulators to avoid unnecessary conflicts. It is not enough to simply say, as in India, that electricity is a "concurrent subject" with regulation shared by national and state regulatory authorities. The nature of the "sharing" has to be defined precisely to avoid costly and distracting conflicts. The areas of regulation actions that are likely to cause friction include

- Transmission siting and certification
- Transmission tariffs
- Bulk power tariffs
- Grid codes
- Commercial and governance rules for regional trading entities and grid operators.

In California and the rest of the United States, the division of regulatory authority has not always been clear or appropriate.

Also, political authorities need to recognize that the division of regulatory authority will probably have to change as the industry structure changes. In particular, a division of regulatory authority that may have been workable under a vertically integrated industry structure may break down as the industry moves to an unbundled, vertically de-integrated structure.

6.4 A Caveat: Regulating State Enterprises Is Different from Regulating Private Companies

Although California provides many useful lessons in "how not to regulate," there is a hidden assumption behind these lessons. It is that the enterprise that is being regulated will respond to the incentives created by the regulatory regime. This may not be true in many developing countries that have recently created new, separate electricity regulatory bodies that are regulating government-owned enterprises. These regulatory entities often borrow regulatory techniques that were developed to exploit the profit-maximizing objectives of private companies, and try to apply these techniques to public enterprises.

However, the inescapable reality is that most public enterprises, despite lengthy and expensive programs to "commercialize and corporatize" them, still usually act like public enterprises. In particular, because they do not pay much attention to profits and commercial performance, many of the attempts to create regulatory incentives are lost on them. As a consequence, regulators who find themselves regulating public enterprises often spend considerable time writing impressive orders filled with directives that, in the words of one new Indian electricity regulator, read like "pretty poetry" but which are "rarely read and almost always ignored."

While it is relatively easy to produce a list of regulatory lessons that can be learned from the California experience, many of the lessons will be inapplicable to a developing country unless the state-owned power enterprise can be made to act like a commercial enterprise (which seems to be rare) or until the state enterprise is privatized.

7. Economic and environmental regulators should talk to each other.

In many developing countries, environmental standards that apply to the activities of state-owned power entities sector have been either non-existent or loosely enforced. Where standards exist, state-owned enterprises, operating with tight budgets and lax maintenance standards, have often acted as if compliance were a low priority. Similarly, the attitude of most environmental regulators has been indifference to compliance by state-owned power entities because of government reluctance to face the costs of enforcing compliance. As power sectors become increasingly privatized, however, governments and their environmental regulators are re-discovering the local and global importance of compliance with environmental standards, and are willing to put more effort into enforcing these standards.

The California experience shows that reform of the way that the power sector is regulated economically should be coordinated with environmental regulation of the sector. Environmental regulation contributed substantially to the high bulk supply prices because it acted as a significant barrier to increasing the supply of electricity in California. The problem was not so much the standards themselves (which continue to be strict), but how they were implemented. Specifically, it took almost twice as long to get state and local siting and permitting approvals for a new generating plant in California as it did in any other U.S. state. The legal and political system allowed inhabitants near the sites of the proposed facilities and environmental groups to block or substantially delay the siting and permitting process for most new generating plants. As a consequence, supply stagnated, while demand steadily increased.

The specifics of power sector environmental regulation—determining which pollutants should be controlled and at what levels, and deciding whether market or non-market control mechanisms should be used—are beyond the scope of this paper. However, it is clear that decisions about the substance and process of environmental regulation cannot be undertaken in isolation from power sector reform decisions. Most electricity regulators would prefer to oppose unduly restrictive environmental standards that raise costs at precisely the moment when electricity prices may need to go up for other reasons. Similarly, most environmental regulators tend to take the narrow view that their mandate is only to ensure compliance with environmental standards. In particular, they do not feel any real responsibility for the overall success of power sector reform or, more immediately, whether a particular plant does or does not get built.

The reality is that these regulators need to work together. Each one is in a position to undermine the work of the other. The ultimate success of both regulators requires a change in their mindsets. The power regulator has to accept that compliance with strict environmental standards is an integral element of power sector reform. The environment regulator must recognize the need to work constructively with developers of new generating plants to help achieve compliance with agreed upon environmental standards.

Part II

From Reform to Crisis in California

1. Background

The reform of the California power market is often characterized as a process of deregulation. In fact, the reform involved limited deregulation by introducing price-based competition in an elaborately structured wholesale power market, and it changed the way that the power market is regulated. It did not involve divestiture of state-owned assets. Hence the reform is more precisely characterized as part deregulation and part re-regulation. The reform also involved some restructuring of market functions by

- Obliging the incumbent utilities to sell some of their power generating capacity to independent suppliers,
- Unbundling their distribution arms from their generation and transmission arms,
- Placing responsibility for grid operation with an independent system operator, and
- Establishing separate markets for energy and ancillary services.

Most U.S. states have started or plan to start programs to deregulate their power markets. California was one of the first to start because of its desire to lower its retail electricity prices. Competition in the power market was introduced through divestiture of generating capacity by incumbent utilities, development of new power plants by IPPs, and extension of competition gradually to retail supply. California's progress in adopting policies that give consumers the right to choose their electricity supplier—the key and ultimate indicator of competition in the market—ranks about average for the 24 U.S. states that have already implemented reforms, according to the Retail Energy Deregulation Index (a scorecard developed by the Center for the Advancement of Energy Markets).

Part II of this paper proceeds in the following sections. First, it summarizes the indicators and consequences of the California power crisis. It then outlines the main parameters of the California power market, describes the formation of the new power market under the 1996 reform, and reviews the factors that led to the crisis. It concludes by assessing whether the crisis could have been avoided.

2. The Indicators of the California Power Crisis

The California power crisis of 2000-2001 has had two distinct phases: (1) during the summer months, when demand rose sharply because the power load from air-conditioners increased under a record-breaking heat wave; and (2) in the winter months of 2000–2001, when power supply fell sharply under seasonally low hydropower output and heavy withdrawals from service of old thermal power units for maintenance.

The serious nature of California's power crisis is shown by numerous indicators for the state's economy that has been the engine of high-technological growth in the United States. Resolution of the crisis is proving difficult and is imposing heavy costs on the stakeholders—suppliers, consumers, shareholders, legislators, etc. The consensus is that there is no way out of the crisis that will be quick, painless or cheap.

- Wholesale electricity prices during 2000 were more than three times the 1999 level. Huge spikes in wholesale power prices occurred during the summer months of 2000. The market was declared dysfunctional by all who studied it then.

- Retail electricity prices in the San Diego area in 2000 were up to three times higher than in 1999; one household reported, for example, an increase in monthly electricity bill from $129 to $353 for the mid-December to mid-January period.
- The first sustained series for decades of brownouts and blackouts occurred during the months of November 2000 to February 2001, when system demand was seasonally low, forcing temporary closures of businesses and social institutions.
- Industrial and commercial users of electricity have been paying massive penalties rather than cutting their power usage under interruptible supply contracts. Electricity is so vital for Silicon Valley that even a one-day power outage, such as the one that occurred in June 2000, reportedly cost as much as $100 million in lost output.
- The two main power utilities are facing bankruptcy, claiming that they have accumulated some $12 billion in uncompensated costs because of the high prices that they have been paying for wholesale electricity from power generators. Each was losing around $400,000 per hour on electricity trading during January 2001. They currently lack the credit to purchase wholesale power, and their debt rating has been slashed to junk-bond status.

The crisis has had the following immediate consequences:

- A Stage 3 alert to power consumers, which had seldom been declared up to the end of 2000, was declared for an unbroken series of 32 days during January and February 2001. A Stage 3 alert is the severest indication of an impending power system brownout or blackout, when the system capacity reserve margin falls below 1.5 percent of peak demand.
- The state government has declared several dozen statewide emergencies to urge consumers to conserve electricity, but this has not been much help.
- The financial crisis caused by the default on payments by the main utilities has threatened to spread to the banking community.
- The Federal Secretary for Energy invoked emergency powers on December 13, 2000, to order power generators to continue selling into the California power market.
- Natural gas suppliers threatened stoppage of deliveries of natural gas to the main power utilities this winter, because they are concerned about the utilities' ability to honor payment commitments.
- The state government has enacted measures that place it firmly in the center of the California power market (e.g., becoming the principal buyer of energy for the two largest utilities), thus effectively flying against the world-wide trend towards deregulation and privatization of electricity trade.
- The main organized wholesale energy market—the California Power Exchange—has ceased to function effectively and faces extinction, because of the utilities' loss of credit on the exchange and a move to long-term contracts for bulk power in response to the crisis.

- Serious power shortages in California are expected to continue for the next two years, especially during the summer months.
- Serious impacts on California's economy are a concern, including threats by businesses to move away, and the repercussions on the rest of the country.
- Other states are reconsidering plans to deregulate their electricity markets. Nevada, for example, has postponed power deregulation plans, in part to stop generators from selling electricity to higher-margin markets in California. Regulators in Arkansas are recommending a two-year delay to their plans.

3. Main Parameters of the California Power Market

The main parameters for the California power market in 2000 are summarized herewith.

- Retail supply of electricity in California is dominated by three investor-owned utilities (IOUs)—Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E)—and two municipal vertically integrated monopolies—Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility Department(SMUD). Their service areas are discrete zones, so they have traditionally not competed with each other for business, except for new industrial customers.
- California currently has about 53,000 MW of installed generating capacity with the following distribution of ownership:

Public agencies comprising the LADWP and SMUD	23%
Renewable energy producers and co-generators, supplying under long-term contracts based on Public Utilities Regulatory and Policy Act (PURPA) legislation	22%
Investor-owned utilities (IOUs)	15%
IPPs, most of which is held by five major power firms (AES, Reliant, Duke, Southern and Dynergy) based outside the state	40%

In addition, California's imports of power provide about 5,000 MW towards meeting system load.

- California's installed generating capacity by type of generator is as follows:

Hydropower	24%
Coal-fired steam generators	6%
Oil and/or gas-fired steam generators	37%
Nuclear	8%
Combustion turbines and combined cycle plant	8%
Geothermal, wind, solar, municipal waste, etc.	17%

- The sources of the 275,800 GWh of wholesale supply of electricity in 1999 by type of energy resource were as follows:

Hydropower	15%
Coal	13%
Oil and/or gas	31%
Nuclear	15%
Geothermal, wind, solar, municipal waste, etc.	8%
Energy imports	18%

This distribution did not change much throughout the 1990s.

- Peak load on California's interconnected power system in 2000 was about 51,400 MW including the loads on the public agency systems. The breakdown of this load by service area was as follows:

PG&E	41%
SCE	38%
SDG&E	6%
LADWP	10%
SMUD	5%

- Retail electricity consumption by sector in 2000 was as follows:

Residential	30%
Commercial	36%
Industrial	21%
Agricultural	7%
Other categories	6%

- Retail electricity prices—expressed in terms of average tariff yield of U.S.cents/kWh—by consumer category for California during 2000 are given below. They show that California's electricity tariffs are about one-third higher than the U.S. average.

	California	*U.S. Average*
Residential	10.6	8.3
Commercial	9.9	7.3
Industrial	6.2	4.5
Other	3.7	6.1
All Sectors	9.0	6.7

4. Formation of the New Power Market under the 1996 Reform

Before the reform, the IOUs were vertically integrated and were able to recover their costs of generating and supplying electricity through the bundled rates that they charged their customers, as long as the sector regulator—the California Public Utility Commission (CPUC)—approved these costs as being "reasonable" and prudently incurred.

The reform of the California power market was implemented according to CPUC's restructuring order issued in December 1995, which led to the enactment of Assembly Bill 1890 (AB 1890) by the California legislature in September 1996. The objective of the reform was to reduce the costs of electricity because California's electricity prices were much higher than the national average under traditional regulation. At the same time, however, the concern was that competition would push wholesale prices so low as to render unviable the investments in new power capacity needed to meet growth in demand, while exposing consumers to high price volatility. AB 1890 was thus designed to deal with these conflicting objectives.

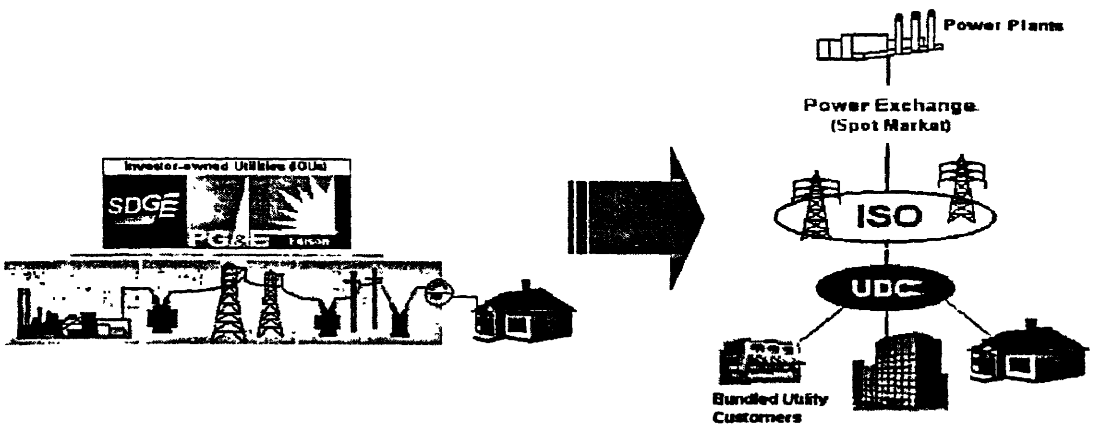
4.1 New Market Structure

The reform established a new market structure (shown in Figure 1) that promotes competition. Separate markets were created for energy, transmission and ancillary services that are procured every hour at market-priced rates through pool-based transactions. Bilateral transactions are also allowed for some participants in the market. The structure was designed to avoid imposing administratively determined commitments, such as capacity obligations, on market participants.

This new market structure was established by the following means:

- A Power Exchange (Cal PX) was created by January 1998. Cal PX is set up as a non-profit public benefit corporation under California legal statutes. It acts as a market place in which generators and suppliers compete to meet demand for electric energy. It functions as an auctioneer and as such does not engage in energy trading on its own account. To ensure the viability of Cal PX, the AB 1890 statute requires the IOUs to sell energy produced from their own power stations (mainly hydro and nuclear) and purchase energy on behalf of customers who had not changed to another supplier (nearly all customers) from the

Figure 1. Electric Supply in California



Source: California ISO

PX during the four-year transition period to 2002. Their retail arms—called Utility Distribution Companies (UDCs)—and electricity marketers purchase energy from Cal PX and resell electricity to their customers.

- An Independent System Operator (Cal ISO) was established to operate the statewide transmission system impartially for buyers and sellers of bulk electricity. Any supplier that meets the regulated reliability standards has access to the system. Cal ISO operates as an independent, non-profit agency. It does not own any generation, transmission or distribution systems, and relies entirely on services supplied from its markets to meet the demands on the statewide power system.
- The IOUs continue to own the transmission facilities and receive a fee for the use of these facilities. The Federal Energy Regulatory Commission (FERC) regulates these transmission use fees and the Cal ISO system operation fees, as well as many of the operating, commercial and technical protocols of Cal ISO and Cal PX.
- Other than the three Californian IOUs, participation in Cal PX is voluntary for all buyers and sellers of bulk power such as municipalities, IPPs and out-of-state producers. They can trade electricity using a variety of means (e.g., bilateral contracts).
- The non-PX participants must submit schedules with the Cal ISO through entities known as scheduling coordinators (SC). The SCs are the only point of contact between these participants and Cal ISO, and they number around forty. They coordinate scheduling activities continuously, and each SC submits a "balanced" schedule to the Cal ISO in which the quantity of energy supplied equals the quantity demanded. Cal PX also submits a day-ahead schedule to Cal ISO.
- PG&E and SCE were required to sell at least 50 percent of their generation plants to IPPs or to place them in separate new companies, in order to mitigate their market power by reduc-

ing their scope for anti-competitive "self-dealing." SDG&E was required to divest all its generation assets (but its parent company was allowed to merge with the local gas supplier). The capacity sold amounted to about 7,500 MW by PG&E, 10,600 MW by SCE, and 2,200 MW by SDG&E, totaling 20,300 MW. Hence ownership of about 40 percent of the total installed capacity in California was transferred to IPPs.

- A California Energy Market Oversight Board was established comprising members appointed by the state governor and legislature, in addition to large stakeholder governing boards for the Cal ISO and Cal PX.

4.2 New Market Operating Arrangements

The reform established separate markets for electric energy, ancillary services, and congested transmission capacity that are operated in parallel by Cal ISO and Cal PX according to market operating procedures approved by FERC. They were launched in April 1998 (except for the Block-Forward market, which was launched in July 1999). They are operated as auctions carried out sequentially throughout the day, with bids for demand and supply. The final price is the highest supply bid that is accepted to clear the market.

- The energy market is structured primarily as a day-ahead auction by Cal PX, with bidders allowed to submit different quantities and prices for each hour. This auction is accompanied by hour-ahead auctions for energy to allow for divergences in demand or supply from the day-ahead bids. Such divergences may occur from unexpected changes in weather conditions or generating plant availability.
- The day-ahead and hour-ahead markets are independent and are closed separately. Upon closing, the winners are financially and operationally obligated to provide the services that are selected by Cal ISO.
- Since scheduled transactions seldom match the actual load on the power system, Cal ISO calculates, in real time, the amount of energy needed to balance total system demand. It conducts a real-time auction for providing supplemental energy or for backing off demand to achieve this balance. Bidders submit prices up to 45 minutes prior to the start of each operating hour. They indicate the prices at which they are willing to change their generation or purchases in real time. Cal ISO uses these bids to balance total generation and load in real time. Prices are established in this market every five minutes.
- Upon certification by Cal ISO, SCs can participate in any or all any of the day-ahead, hour-ahead, and real-time markets. SCs are not required to schedule all of their expected load and generation in the day-ahead market. They may elect to bid for less than their expected load in the day-ahead market, and then cover their remaining load in the hour-ahead energy market. Deviations from their day-ahead or hour-ahead schedules are allowed by Cal ISO, and settled on the basis of real-time energy imbalance market prices.
- Every day, Cal ISO collects energy schedules from the SCs and assesses the viability of each schedule. Individual schedules accepted by Cal ISO are aggregated into a master schedule that is checked to ensure that it can be accommodated by California's bulk

power grid in a reliable and safe manner. If Cal ISO identifies power system problems such as congestion in parts of the grid, it provides the markets with an opportunity to adjust schedules in order to alleviate the problems.

Cal PX operates a Block-Forward market that allows participants to enter into electricity supply contracts for physical delivery up to six months into the future. These contracts provide a hedge against spot-market price volatility.

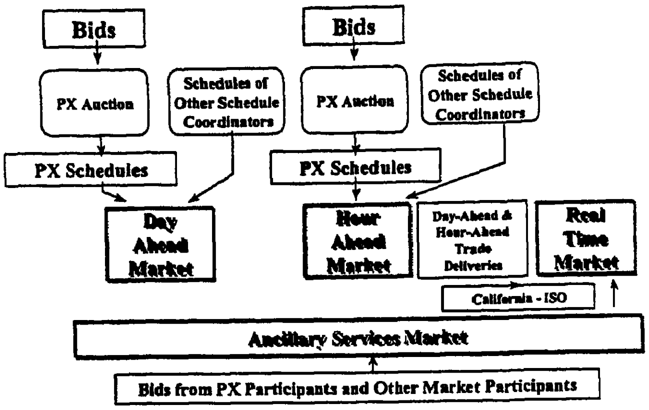
Cal ISO purchases ancillary services (for black starts, frequency control, spinning, non-spinning and replacement reserve generating capacity available at short notice) in an unbundled manner from generators through long-term contracts and competitive bidding.

Cal ISO ensures reliable operation of the transmission grid by holding an auction for allocating congested transmission capacity among the various system users after Cal PX has established preliminary hourly day-ahead prices for energy. To facilitate this allocation, Cal ISO accepts "adjustment bids" for both the day-ahead and hour-ahead markets. These bids reflect the prices at which SCs are willing to procure more energy or curtail loads from their preferred schedules. If market participants do not submit sufficient adjustment bids, Cal ISO levies a congestion management charge on the schedule that utilizes congested transmission lines.

Generators receive no capacity payments or payments for start-up costs in the energy market. Hence they must recover their fixed costs through direct payments received for energy on Cal PX sales, as well as through the Cal ISO ancillary services market.

- Open and flexible scheduling opportunities are characteristic of the market framework. For example, a generator may bid into multiple Cal ISO markets and have multiple delivery points. It can have a bilateral transaction with another market participant, sell a portion of its output to Cal PX, sell another portion to the Cal ISO ancillary services markets, and export a part of its output out of state.
- A generator faces a complex set of decisions concerning whether to sell capacity into an earlier or later auction, as well as between selling it for energy or ancillary services. Each decision to sell potentially forecloses opportunities to sell into other markets. For example, a sequence of decisions facing a generator could be whether to bid (1) into the day-ahead energy market at 7 a.m., for which the results are declared about one-and-a-half hours later; (2) into the ancillary services market at 11 a.m., for which the results are declared by 1 p.m.; or (3) into auctions throughout the day in the hour-ahead and real-time energy markets. Market participants have the opportunity to place bids up to five hours before power flows in the Cal PX day-ahead market, two hours ahead in the Cal ISO hour-ahead market ancillary services market, and 45 minutes ahead in the Cal ISO real-time imbalance energy market.
- Apart from these centralized markets, there are separate bilateral transactions involving parties such as Californian generators who are not obligated to trade through the Cal PX, out-of-state generators and Californian buyers other than the three UDCs.

Figure 2: Overview of Market Operations


Bids
PX Auction
Schedules of Other Schedule Coordinators
PX Schedules
Day Ahead Market
Bids
PX Auction
Schedules of Other Schedule Coordinators
PX Schedules
Hour Ahead Market
Day-Ahead & Hour-Ahead Trade Deliveries
Real Time Market
California - ISO
Ancillary Services Market
Bids from PX Participants and Other Market Participants

The market operating arrangements are depicted in Figure 2.

4.3 New Market Regulatory Framework

The reform changed the way the power market is regulated as follows:

- *Commitment of the contractually agreed capacity with Cal ISO for a specified term (generally one to two years) of power plants sold by the IOUs as "Reliability Must Run" (RMR) to maintain system stability and to overcome local congestion on the transmission system.* "RMR" designation for a generating unit means that the owner must commit to maintaining the unit and to responding on a best-efforts basis to a directive from Cal ISO to operate the unit. The owners of RMR units are required to bid all of their contracted capacity into Cal PX. Hence they do not participate fully in the Cal PX market. Ironically in view of the events during 2000, Cal ISO designated RMRs soon after the new market started because of concerns about ultra-low clearing prices in its imbalance market. In this situation, the relatively high-cost thermal power generators in southern California would not win business in the market and therefore have little incentive to participate in it. Cal ISO was concerned about the availability and dispersion of sufficient reserve capacity so that the transmission system could absorb the loss of major transmission lines between northern and southern California.
- *Introduction of a competitive transition charge (CTC) on customers' electricity bills for the recovery of the IOUs' stranded costs arising from the introduction of competition.* These costs refer to the relatively high operating costs and debt-service obligations (usually referred to as *stranded costs*) for some of the IOUs' generating plants built before the 1990s. The CTC is computed for each user's bill as the difference between the regulated rate and the cost of supply. The regulated rate is frozen for all retail users until the IOU that serves them has recovered its stranded costs under the CTC. California's utilities had recovered more than $11 billion under the CTC by the summer of 2000, and SDG&E had fully recovered its costs so that its rates were unfrozen. The transition cost-recovery period lasts up to December 31, 2003, after which retail sales are no longer frozen by statute.
  - The CTC is also used to help recover the high costs of power procured by the IOUs under PURPA-mandated contracts with certain renewable generation and co-generation facilities (termed qualifying facilities, or QFs). These QFs provide up to 30 percent of the electricity produced in California. This high proportion

reflects the state's aggressive pursuit of electricity from these types of facilities during the 1980s. The high prices (averaging around 17 U.S. cents per kWh) paid to the QFs under the terms of these contracts would make these plants uncompetitive under anticipated market conditions (i.e., conditions that prevailed before 2000) without the CTC. The prices in many of these contracts were tied to CPUC predictions of world oil prices, but these predictions proved to be inaccurate.

- *Imposition of a 10-percent rate reduction for all residential and small users from January 1, 1998, to last for four years.* This reduction was funded by the issuance in December 1997 of $6 billion worth of 10-year rate-reduction bonds by a special purpose trust authorized by the state.
- *Regulation of the distribution component of retail tariffs for the UDCs* will be based on performance-based ratemaking.
- *Initiation of retail competition.* Suppliers have competed actively for the business of large commercial and industrial users. Retail competition has not progressed beyond 2 percent of the market in the market for residential users (except for a niche market for "green power") because of the freeze on retail rates and the inclusion of the CTC in customers' electricity bills.
- The California Public Utilities Commission (CPUC) continues to regulate the UDCs' distribution activities.

In addition, fossil-fueled power generation is subject to strict and a rather unique environmental regulation that pre-dates the 1996 power market reforms. In particular, a Regional Clean Air Incentives Market (RECLAIM) for Nox. Retail Emissions Credits, or RTCs had been established with the total allowed emissions in a district to be lowered over time so as to reduce urban smog. Regulated firms are allocated a fixed number of RTCs for NOx emissions for each year, and they are required to redeem these RTCs according to the amount of their NOx emissions. Regulated firms can buy RTCs from other firms to overcome a shortage for meeting their requirements, and sell RTCs in excess of their needs. These trades set up a market in RTCs, both for the current year and for future years ("vintages") in order to prevent a "NOx spike" of higher-than-anticipated emissions. Firms are not allowed to combine RTCs of different vintages.

5. Main Factors that Led to the Crisis

The California crisis centered around the three UDCs and their suppliers through the Cal PX. Other power entities, such as the municipal utilities that chose not to participate in the Cal PX, have not been so affected by crisis. This difference indicates that design flaws in the Cal PX market are a major source of factors that led to the crisis.

Nevertheless, a number of factors exogenous to the market design worsened the problems created by the design flaws. In particular, the crisis arose out of an unpredicted combination of events. Undoubtedly the most important was the shortage of power supply relative to demand. In the summer crisis, demand increased to around 51,400 MW—30 percent above the winter level. In the winter the supply capacity was reduced by more than 20 percent as thermal plants were taken out of service for deep maintenance, and an unusually dry end to the year 2000 in the Pacific Northwest left reservoir levels low and thus limited the amount of hydropower that California could import. The other factors have exacerbated this problem.

5.1 Market Design Flaws

Structural and operational flaws in the California power market became evident within a year after the ISO and PX went operational in 1998:

- *A mismatch between the regulated retail market and the deregulated wholesale market.* While wholesale electricity prices and natural gas prices are deregulated, retail electricity prices are fixed for the UDCs until they have recovered their stranded costs through the CTC or by December 31, 2003, whichever is sooner. Hence increases in wholesale power costs cannot be passed through to retail users, thus exposing the electricity distributors to huge potential losses under their obligation to serve their customers. This flaw does not become serious unless wholesale prices rise above the retail rates, which they were not expected to do at the time that the reform was being introduced. This flaw may be only transitory, but it has contributed to the onset of the crisis during the transition period.
- *Lack of economic incentives for adequate capacity to maintain supply reliability standards.* The UDCs were not obliged to contract capacity, nor were generators recompensed specifically for providing capacity. Long-term forward contracting of energy by the UDCs was also not allowed. Finally, the lack of forward energy markets for some years ahead suppressed the price signals that would have helped the distributors and investors in generating capacity to assess the need for new capacity.
- *Lack of risk-mitigation options for distributors.* The UDCs were not allowed full access to forward markets, and so were not able to develop a risk-minimizing power portfolio. During 2000 they acquired only about 6 percent of their energy from forward markets, in contrast to 34 percent from their own generating plants and 60 percent from other suppliers on the Cal PX market. They were not even allowed to sell their power plants with long-term vesting contract protection against price volatility. Instead, they have had to rely on volatile spot markets. Hence, they were forced to "sell long and buy short," which is disastrous for a trader in any commodity.
- *Demand inelasticity.* Lack of demand elasticity by UDCs in the energy markets arises from their inability to curtail their demand to avoid paying high prices, because of their obligation to serve the demands of their captive customers. Just as a relatively small amount of tightening of the supply/demand balance in the absence of any demand elasticity produced the summer price spikes in the Cal PX market, so a relatively small amount of loosening of the supply/demand balance in the presence of some demand elasticity would have significantly mitigated the pressures that produced price spikes.
- *Price caps.* Facing virtually no supplies in the real-time balancing energy market to meet system imbalances, the Cal ISO was authorized by FERC to impose during 2000 progressively lower "soft" price caps on bids in the real-time balancing energy market, starting at $750/MWh during the summer and dropping to $250/MWh by the end of the year. Payments made by the UDCs above the price cap

would be subject to scrutiny and cost-justification by Cal ISO in retrospect. These levels would amply cover the costs of power generation under normal trading conditions, but \$250/MWh was insufficient to cover even the variable operating costs of the older power plants during the periods of very high gas prices and high costs of NOx emission permits. The situation appeared to provoke generators into raising their bids for supply during off-peak periods to recover their losses under the price caps during peak periods. These caps also appeared to limit prices to below the opportunity costs of other units providing replacement reserve, hydro units constrained by lack of water, and thermal units constrained by emissions limits, as well as exporters to neighboring markets which were also experiencing high prices.

- *Market arbitrage by generators.* Since the markets for energy, transmission congestion rights and ancillary services are cleared sequentially, rather than together, Cal ISO faces heavy demands on coordination to prevent arbitrage by market participants that leads to inefficient dispatch of generating plants and higher prices than predicted under models of these competitive markets. This sequencing gives incentives to generators to collect high premiums for real-time energy and ancillary services by withholding supply (or by putting in such high bids as to be sure that they won't be accepted) from the day-ahead energy market, and then bidding more supply into the other markets. Such profit-maximizing incentives for generators bidding into these multiple markets may account for some of the observed price spikes under supply shortages during 2000. For example, a generator would set a bid in the energy market for a segment of capacity to cover at least the foregone expected earnings in the ancillary services market for that segment, and this bid could be a very high hourly rate to cover these foregone earnings if the generator expects the segment to be dispatched for only one or two hours in the energy market. Likewise, prices in some markets for ancillary services could be driven up by considerations of foregone earnings in markets for other ancillary services. Some observers also allege that the repeated rounds of bidding under the market structure provide generators with scope to "game" the system by adjusting their bidding strategies to their advantage merely by observing each others bidding behavior without collusion in the accepted legal sense.
- *Market arbitrage by UDCs.* Since the Cal PX capped prices in the day-ahead energy market at a much higher level (\$2,500/MWh) than the Cal ISO's cap in the real-time balancing market, the UDCs have kept down their demand purchases in the day-ahead market by under-scheduling their during hours when price spikes would otherwise be likely to occur. They have done this to keep the price in this market below the cap in the real-time balancing market, thus effectively capping the rate they pay at the lower level of the latter. Purchases on the real-time balancing spot market have constituted a higher proportion of total traded energy in Cal PX (20–30 percent of the total energy procured) than in other U.S. states and other countries that have forward contracts in their power markets, since a balancing market usually handles less than 5 percent of total trade. This fea-

ture appears to have contributed significantly to the large volatility in prices in Cal PX.

- *Market power.* The potential for market power is likely to exist in a deregulated price-bid market such as the California wholesale market, especially in the presence of local market segments created by transmission constraints. This potential takes the form of artificial scarcity of power created by power generators to drive up prices and earn huge profits. The potential for abuse of market power by generators increases significantly during periods when supply falls short of demand. Some experts contend that the generators' exploitation of market power caused a significant portion of the huge price spikes for a few hours during 2000 in the California wholesale electricity market. Others go further by alleging persistent and serious abuse of market power by generators. Likewise, some observers allege that common ownership of one of the main gas suppliers and critical gas pipeline capacity in southern California created the conditions for market power in this market. After auditing plant outages in California, however, FERC staff stated that they did not find evidence of certain practices that indicate abuse of market power by the audited companies. It is generally acknowledged that it is difficult to distinguish from available data the exercise of inappropriate market power from the exploitation of legitimate scarcity rents when a market is in short supply.
- *Market governance.* Poor governance structures contributed to the problem. The large size and politicization of the boards of Cal ISO and Cal PX, through quotas of stakeholders each representing their own interests, hampered attempts to focus on getting the market to work. The governance arrangements for Cal PX give to some parties the voting power to block changes to market rules, which was done out of concern about putting market power in the hands of the UDCs. This led to the prohibition of trading on forward markets by the UDCs. Likewise, it is alleged that generators have too much power in Cal ISO, which they have used to block proposals to force them to schedule their entire output in the day-ahead market. In late 2000, FERC ordered the replacement of Cal ISO's stakeholder board by a non-stakeholder board.
- *Retail competition.* Less than 2 percent of California's retail electricity users have migrated from the incumbent UDCs to alternative Energy Service Providers (ESP). Most ESPs have exited the California market after their failure to attract customers. The failure to develop retail competition in California results from a policy of charging retail users a default price equal to the wholesale power price, rather than the retail market price, and by allowing the UDCs the right to provide default service. Default service refers to electricity supply provided to those customers that are not receiving service from a competing supplier. It is a regulatory device used to smooth the transition to a competitive retail market or as a long-term alternative to it. The amount by which the default service price exceeds the wholesale price dictates the level of customer savings and supplier earnings, which are fundamental drivers of retail competition. Generally, the higher the default price relative to the wholesale price, the more intense the

competition and switching to new suppliers.

The presence of these flaws raises the issue of how the process for reforming the California market was managed. A consensual process was adopted, so that interested parties influenced the design in ways that possibly caused these flaws. This process resulted from the difficulty in changing market structures when (1) the ownership of the means of supply is diversified among private interests that possess property rights by virtue of their ownership and (2) other parties, such as consumer and environmental advocacy groups, have the legal right to mount strong legal challenges in defense of their interests, as in California.

5.2 Exogenous Factors

Constraints on Expanding Supply

- No new power generation capacity has been commissioned in California since 1992 because (1) uncertainty about the new power market deterred investors until the new market structure and regulations were finalized in 1996, and (2) subsequently excessive delays occurred in obtaining siting permits for new power stations in the face of local opposition when investors submitted applications.
- Investors have been deterred from entering the California power market by the expense and uncertainty of the extenuated permitting process for new power stations and transmission lines, exacerbated by the ability of people dwelling in the vicinity of the proposed facilities to initiate numerous legal challenges. The propensity of California's consumer and environmental groups to use ballot measures to oppose new power plants has added to the delays and uncertainty for investors in these plants. However, in the last two years the state has licensed nine new power plants (totaling 10,600 MW), and five (totaling 2,900 MW) are under construction. These plants will contribute significantly to easing the supply shortage, but only in about two years' time.
- A drop in imports of power from neighboring states occurred because of low hydropower production caused by a drought and a growth in demand for electricity in these markets. Environmental safeguards to protect fish populations in the Pacific Northwest region further limited the water available for generating electricity. These imports formerly provided an important source (20 percent) of California's power needs, especially during the peak demand period in summer months.
- Power stations and transmission facilities are old. Nearly 60 percent of California's power plants are at least 30 years old, and now need more maintenance and thus longer outage periods than modern power plants. The withdrawal of about 10,000 MW of this plant for maintenance, as usual during the low-demand winter period, helped create the end-2000 supply shortages.

An Unexpected Increase in Demand

- The growth of Internet-based power consumption based on Silicon Valley industries spearheaded a 25-percent increase in statewide demand during the 1990s, but this statistic hides the real problem. From 1988 to 1998, electricity demand grew at an average rate of only 1.3 percent per year. In 1999 and 2000, however, electricity demand on the Cal ISO system surged unexpectedly. In June 2000, energy demand was 12.5 percent higher than in June 1999, and peak demand was 6.2 percent higher.

- Demand for electricity in the summer of 2000 was pushed up by air conditioning loads under the highest temperatures for May to July recorded for 106 years.
- Retail demand was not sensitive to increases in the costs of wholesale power since the tariff rates for most consumers in California were frozen until the utilities collected all their stranded costs under a regulated surcharge on customers' electricity bills. In addition, lack of demand elasticity by retail electricity buyers arises because they only discover the prices that they are paying after the transaction, and then only in terms of an average monthly price rather than hour-by-hour prices. Relatively few users have time-of-use (TOU) meters.
- Failure to meet demand reliably for electricity—especially through blackouts and brownouts—is enormously costly for power users who have already adjusted to using grid power. Californian users of electricity showed their willingness to pay huge penalties under interruptible supply contracts rather than reduce power consumption when called upon to do so by their suppliers.

A Steep Increase in the Cost of Wholesale Power During 2000

- The market clearing price in the day-ahead Cal PX energy market oscillated between $25 and $50/MWh during 1998, 1999 and the first half of 2000, and then rocketed to over $150/MWh in June, July and August 2000 during an extreme heat wave. The steep increase in price occurred when supply started to fall below demand, even though prices did not move discernibly beforehand as the margin diminished between supply and demand. Electricity markets do not have the price stabilizing mechanism of buffer stocks because electricity cannot be stored economically.
- The average price of natural gas across the country also shot up during 2000 due to growth in demand, because gas is the fuel of choice for the huge amount of power-generating capacity recently commissioned or under construction. The shortage also reflects a slowdown in gas exploration during the second half of the 1990s, when oil and thus gas prices were low. This price increase occurred when much more gas was used in 2000 than in 1999 for generating power in California because of higher demand for power and lower supply from other power-generating sources.
- The price of natural gas in California reached extraordinarily high levels during a spell of cold weather in December 2000 (gas is used for space heating as well as power generation). In December gas sold daily on spot markets at major terminals averaged around $11 per thousand cubic feet (TCF), compared to around $2.5/TCF in the preceding years. This increase in gas price added about $75/MWh to the operating cost of a typical old power plant in Southern California that was supplied with gas bought on the spot market. Daily prices reached at times more than $60/TCF at the southern border of California during the first week of December 2000, partly due to bottlenecks in the California gas pipeline system. However, a large proportion of gas purchases by gas traders and suppliers was hedged,

and hence they were less exposed to gas price volatility than UDCs were to electricity price volatility.

The design of NOx emission regulations—restrictive levels of annual emission permits complemented by a market for emission credits—has caused owners of older generating plants in California to pay a high price for these credits. Given power supply shortages, these plants were under pressure to utilize their capacity above the level that would allow them to meet the NOx emission standards. In the South Coast Air Quality Management District of California (SCAQMD), the allowed NOx level was reduced on July 1, 2000, which reduced the supply of NOx RTCs just when demand for them increased. Consequently the cost of a vintage 2000 RTC increased from around $3/lb. NOx between 1997 and mid-2000 to around $45/lb. NOx by end-2000. This increase in price for NOx emission credits pushed up the variable operating costs of a typical Southern California power plant by around $30/MWh.

5.3 *Exodus of Funds by Utilities*

The holding structure adopted by the three IOUs has enabled these companies to keep substantial funds out of reach of the creditors of the UDCs as the latters' debt mounted through 2000. If they had been available, these funds would have been sufficient to defer the current financial crisis, and thus to provide some time for implementing corrective measures to prevent the development of the financial crisis. From the mid-1980s, the CPUC authorized the creation of holding companies, in which the utilities were relegated to the status of subsidiaries. The parent companies were permitted to pursue other, unregulated businesses as long as those activities did not compromise the utilities' ability to serve customers or the capital needs of the utilities.

Independent audits of SCE and PG&E released by the CPUC recently showed that the UDCs transferred billions of dollars to their parent companies during the first years of deregulation. The parent of SCE received $4.8 billion and the parent of PG&E received $4.6 billion between 1997 and 2000 from their Californian utilities. These funds were derived from the sale of their Californian generating plants, the surpluses earned through the sale of power in Cal PX from their remaining generating plant, and the recovery of stranded costs under the CTC. The parents used this cash to finance most of their dividends and for the acquisition or construction of power generating capacity in other states and abroad. The parent companies of these UDCs have instituted so-called ring-fencing provisions designed to prevent bankruptcy courts or anyone else from using the parents' unregulated assets to cover the debt of the UDCs. These steps have aroused considerable controversy in California.

6. Could the crisis have been avoided?

In assessing the impact of the design of the California power market on the current crisis, the issue is whether design flaws have made a serious situation unmanageable. The fact that this arrangement worked without major trouble for the first two years indicates how easy it was to fall into a false sense of security while market fundamentals were heading for a crisis. In the case of California, these fundamentals were strongly rising demand, no new capacity, decline in hydropower output, and surging natural gas prices. Once the crisis hit the market, the opportunity for making adjustments smoothly had been lost and the impact was magnified by the flaws in the market design.

Other states experienced spikes in wholesale electricity prices similar to those in California, but only for a few days at a time. Only California experienced a persistent series of such spikes throughout the summer of 2000. Retail prices in some other states have also risen by similar proportions to the trebling of rates in the San Diego area. Likewise, natural gas prices have risen on average by similar amounts across the United States, although they have risen much more at times in parts of southern California due to pipeline congestion. But the other states have not experienced the brownouts and financial crisis that afflict California.

Two avoidable design flaws stand out:

1. UDC's unhedged exposure to spot prices, especially when tight supply conditions were foreseeable. The regulators eventually tried to help the UDCs diversify this risk, as described immediately below, but their efforts appeared to be a case of "too little, too late."
2. Retail prices capped at levels that depended on low prices in the wholesale power market for sustainability. Despite intense political and consumer opposition, the CPUC has recently approved an emergency rate increase of 9 to 15 percent to relieve some of this pressure.

The utilities could have tested the proposed structure in the market before taking irreversible steps, for example by offering their generating plants for sale with vesting contracts on terms that were affordable under the capped retail prices. A lack of takers from IPPs for such contracts would have indicated that the proposed structure was unsustainable.

The higher-than-expected prices that the IPPs paid for the IOU's generating plants possibly indicated that they expected spot prices to be much higher than the levels at which the UDCs could survive within the capped retail rates. Other explanations for these high observed prices are the potential value of generation capacity on the plant's site, and the expectation of obtaining major gains in operating efficiency.

After experiencing extreme (up to that time) price spikes during the summer of 1998 shortly after Cal PX opened, SCE sought CPUC's permission to buy 2,000 MW—about 10 percent of the peak summer demand of its customer base—outside the Cal PX. This move was opposed by consumer groups, electricity sellers and other stakeholders. CPUC rejected SCE's request on the grounds that such purchases would weaken Cal PX and put the smaller electricity sellers at a competitive disadvantage on the Cal PX.

Cal PX tried to help the UDCs protect themselves from price fluctuations by offering forward contracts for up to 18 months in April 1999. CPUC gave the UDCs permission to enter into such contracts, with limits on how much electricity they could buy that way, and so Cal PX opened its Block-Forward market in July 1999. As prices kept rising, the UDCs asked for more, and CPUC generally granted these requests, sometimes months later. In July 2000, PG&E asked CPUC for emergency authority to buy power outside Cal PX, which CPUC approved in August in the face of the full-blown crisis.

The UDCs sometimes hesitated to use their freedom fully to enter into such contracts because of concern about CPUC's ability to cut their profits later in a "prudency review" if it deemed the contract terms unacceptable. This might occur if spot prices dropped below the level of prices under long-term contracts before the contracts expired. So both options open to the UDCs were risky, and generally the spot market was chosen by them.

The market based NOx credit trading system, whose perceived advantage is reduction in the cost of achieving compliance for the industry, in fact appeared to contribute to the increase in marginal supply costs of electricity when supply was constrained in the Summer of 2000. For example, "NOx spikes" can occur on days when electricity demand is greatest (due to air-conditioning load, for example), because electricity spot prices can then rise sufficiently to encourage plant operators to pay high prices for NOx RTCs so as to run power plants at maximum output. This indicates the possibility of interaction between environmental and energy costs when both are determined by market clearing prices.

Inadequate transition arrangements also appear to have contributed to the crisis. The Californian "big-bang" approach to deregulation is open to the risks of unexpected market conditions, as well as the unexpected ability of participants to "game" the market. Market rules and highly sophisticated software, hardware and telecommunications systems were developed in only 12 months, completely independently of any market participants. A structured transition strategy is needed that is based on planning for steps that might be taken if crucial assumptions, such as continuation of surplus power supply capacity and low natural gas prices, proved to be wrong. In particular, the IOUs mistakenly anticipated earning huge margins during four competition-free years in which to recover their stranded costs. Cal ISO was forced to make ad-hoc adjustments such as introducing price caps to deal with these unexpected events; these adjustments provided quick fixes but led to further problems.

California's inclination to rely on power imports, rather than expand its own supply capacity, exposed it to developments beyond its control. Neighboring states object to being energy farms for California, whereby the latter avoids the environmental consequences of building new generation capacity while benefiting from the output. They are also unhappy about the increases in prices in their power markets that they attribute to events in the California market.

One indicator of whether California could have avoided its crisis by better market design is the existence of workable deregulation of a power market elsewhere under similar market conditions in the United States such as in Pennsylvania, Texas and Illinois. Another indicator of California's specific vulnerability is the experience of its neighboring states under similar supply constraints and growing demand. Wholesale power prices during the summer months of 2000 also rocketed in these states, partly due to the rise in California's wholesale power prices, but their utilities did not hit the severe financial crisis that has floored the state's main utilities.

In Pennsylvania, where the state restructured the electricity market with far less political influence on the design, the state PUC set a high cap on wholesale prices to secure an upper limit, and did not require utilities to sell their generation plants. Buyers and sellers are allowed to choose whether to exchange in the power pool or through direct contracts with financial hedging through "contracts-for-differences." A capacity market exists in parallel with the energy market. They have not experienced the shortages faced by Californian power users for these reasons and also because the Pennsylvania power system benefits from extensive interconnections with other regional power markets; also, coal is widely used for power generation, which hedges against increases in natural gas prices. Independent power producers are developing nearly 40,000 MW of new generation capacity in the state. Retail competition is promoted by a high default cost (considered to be too high by some commentators) and by mandatory reallocation of retail customers from the incumbent suppliers, so that around 10 percent of customers have switched supplier.

Overall, three conclusions may be drawn from the California power crisis:

1. The flaws in the design of the California market contributed substantially to the financial crisis of California's main utilities.
2. Efforts to deal with the crisis in the presence of these flaws could not have succeeded.
3. A properly designed power market could have coped with the factors leading to the crisis. Because the reforms already undertaken in the California power market prevent a return to the pre-reform structure, the state's only option is to correct these flaws and move forward to a better-designed market

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The Electricity Bill, 2001

As introduced in Lok Sabha
on 30.08.2001

K. Ramanathan
Senior Fellow

16 October 2001

Constitutional Provisions

- Electricity a concurrent subject
- Parliament and state legislatures both have powers to legislate
- Central legislation shall prevail over state Act except when state enacts legislation with Presidential assent

Existing Legislations

- IE Act, 1910
- E(S) Act, 1948
- ERC (Electricity Regulatory Commissions Act) 1998
- Reform Acts of the states of
  Orissa (1995)
  Haryana (1997)
  Andhra Pradesh (1998)
  Uttar Pradesh (1999)
  Karnataka (1999)
  Rajasthan (1999)
  Delhi (2000)

What the Act Aims to Achieve

- Consolidation of existing central Acts
- Formulation of National Policy & Plan
- Reorganisation of SEBs
- Delicensing of generation
- Recognition of trading as distinct activity
- Define the constitution & functions of ERCs
- Creation of an Appellate Tribunal
- Opening up of market in a phased manner
- Giving a revenue focus to theft of electricity

National Electricity Plan & Policy

- GOI to prepare policy (including tariff policy) in consultation with SG's and CEA for optional utilization of resources including conservation and use of RE.
- CEA to prepare National Plan every 5 years.
- GOI in consultation with SGs and SERCs to formulate policies for rural electrification and local distribution in rural areas.
- SGs to endeavour supply to all areas including villages and hamlets.(USO)

Generation of Electricity

- No license required, except in case of HE stations where CEA's concurrence needed
- Should comply with relevant technical standards and submit requisite information to ERC, CEA and CTU/STU
- Distribution companies can also set up generation
- CPPs: No sanctions needed, right for open access to wheel power to its industrial units
- All generators subject to grid code when connected with the grid

HE Stations

- Impact of riparian rights of other states
- Prospects of ultimate development of tributaries for generation, navigation and flood control
- Optimum location of dams and other river works
- Norms regarding dam design and safety
- Multi-purpose schemes: SG and Genco to co-ordinate with others so far as interrelated

Licensing

- License needed for
  - transmission,
  - distribution and
  - trading
- ERC may grant exemption on recommendation of appropriate govt. to local authority, panchayat institutions, user association, co-ops, NGOs or franchisees
- Licensing terms and conditions as spelt out in the Act and Regulations

Revocation of license

- ERC may revoke license in case of
- Wilful and prolonged default in abiding by the licensing conditions,failure to discharge duties and obligation etc.
- 3 months notice to be given
- Reasonable opportunity for licensee to represent
- ERC may instead of revoking license permit it to remain in force subject to further terms and conditions

Suspension of license

- ERC may suspend distribution license in case licensee has broken terms and condition, fail to maintain quality of supply etc.
- Reasonable opportunities should be given to the licensee to represent
- ERC may appoint an administrator to discharge the function of the licensee for a period not exceeding 1 year
- License to be revoked or suspension revoked within 1year. In case of revocation of license utility to be sold within 1year of revocation.

Transmission of Electricity

- GOI may make demarcation of regions
- Hierarchical set up of load despatch centers
- NLDC/RLDCs to be set up by GOI,SLDCs by SGs.The LDCs to be owned by a govt. company
- CTU (notified by GOI) for inter-state and STU (notified by SG) for intra-state transmission system, functions specified
- CTU/STU may engage in other business (except trading) with the approval of ERC
- All to comply with grid standards & grid codes

Functions of RLDCs & SLDCs

- RLDC to be apex body to ensure integrated operations in the region: SLDC in this state
- SLDCs to comply with all directions with RLDCs
- The LDCs responsible for optimum scheduling and dispatch, real time monitoring & control of grid operation, keeping accounts of energy transactions etc.
- Dispute may be referred to ERCs.
- The LDC may levy and collect fees and charges
- Provision for Regional Power Committees.

Supply of Electricity

- Distribution licensees duty bound to supply to owner or occupier of any premises
- Specifies time limit for new connection (1m/6m)
- Distribution license to allow wheeling as per regulation of SERC.
- Open access to be introduced in phases subject to conditions as (enabling provision for surcharge over and above wheeling charges to be utilized to meet cross subsidy & USO)
- Licensee may engage in other business with approval of SERC

Supply of Electricity(cont..)

- Duties of traders to be specified by ERCs
- CEA to specify suitable measures in matters relating to safety
- No unmetered supply beyond 2 years. ERC may extend time through notification.
- ERC to set standards of performance, provision for compensation for non - conformance
- ERCs may issue directions to a licensee or generating company in case of abuse of dominant position or causing adverse effect on competition

Tariff Regulations

- SERCs to be guided by principles and methodology specified by CERC, commercial operations, promotion of efficiency, reduction of subsidy, MYT principles, promotion co-gen & RE, National Electricity Policy,etc.
- May adopt tariff determined through bidding
- SERC having jurisdiction of the distr licensee to decide tariff in case of inter-state supply
- Draft tariff order to be published

Functions of CEA

- Advise GOI on policy, formulate plans, co-ordinate activities of planning agencies
- Specify technical standards
- Appraisal of HE stations
- Promote timely completion of schemes
- Promote research, training,
- Investigations for the purpose of generation transmission & distribution
- Advise SGs, ERCs, licenses or Gencos on technical matters
- Collection, collation and publication of data

Central Regulatory Commission

- Chairperson + 3 Members + Chairman CEA
- Qualifications: Engineering, finance, economics, commerce, law or management
- GOI may appoint judge of SC or CJ of HC as Chairperson with approval of CJ of India
- 6 Member selection committee under the Chairmanship Secretary Planning Commission
- Term of office 3 yrs; reappointment possible for another 3 years. Age limit 65 years
- Commercial employment not allowed for 2 yrs after demitting office

Functions : CERC

- Regulate tariff of gencos under GOI, composite schemes for generation, ISTS
- Regulate inter-state transmission (ISTS)
- Licensing of transmission and trading (Inter-state)
- Fix margin for industrial trading
- Advice GOI on policy promotion for investment
- Specify grid code, formulate regulations
- Adjudicate disputes and refer to arbitration.

State Regulatory Commission

- Upto 3 Members. Chairperson could be judge of the High Court
- 3 Members selection committee under the chairmanship of judge of the High Court
- Term of office 3 years, extendable for a second term. Age limit 65 years
- Ban on commercial employment for few years after demitting office
- Enabling provision for Joint Commission for two or more states/Union Territories

Functions : SERCs

- Determine tariff for generation, supply, transmission and wheeling of power
- Regulate electricity purchase and procurement process
- Facilitate intra state transmission wheeling
- License transmission, distribution and trading within state
- Specify grid code and supply code, enforce quality of supply & service
- Adjudication and arbitration
- Advise state Government.

Other Provisions

- All proceedings deemed judicial within the meaning of sections 193& 228 of IPC
- Govts empowered to give policy directions to CERC, SERC, Joint Commissions
- Creation of CERC/SERC Funds with grants and loans from govt., fees received by ERC, sums from other sources as decided by Government

  This fund to be used to meet all expenses of ERC including salaries, audit fees, etc.
- ERCs to forward budget for the next Financial Year to Government.

Reorganisation of SEBs

- Vesting of property of SEB in SG on date stipulated by SG
- Property to be revested by SG in companies as per transfer scheme
- Asset value to be determined, as far as may be, based on revenue potential
- Priority to use of proceeds of sale (to non-Govt. Cos.) to clear dues to staff and payment of loans/other liabilities of transferor co.
- Terms & conditions for personnel shall not be less favourable

Offences and Penalties

- Theft of electricity a cognizable offence - punishable with imprisonment for a term (upto 5 years) or with fine or with both
- Penalty for non compliance of direction of ERC upto Rs one lakh with additional penalty upto Rs 60,000 per day
- Whoever abets the offence is punishable
- Compounding of offences allowed once for any person or consumer

Appellate Tribunal for Electricity

- To hear appeals against orders of ERCs and adjudicating officers
- Chairperson + upto 3 Members.
- Jurisdiction may be exercised by benches. Atleast one technical and one judicial member
- Chairperson should be/have been a judge of Supreme Court or Chief justice of High Court
- Age limit 70 years for chairperson, 65 for others
- Appointment for 3 years, eligible for 2nd term
- Appeal to Supreme court

Co-ordination Forums

- GOI to Constitute (a) a Co-ordination Forum consisting of chairperson and members of CERC, chairperson of CEA & representatives of Gencos and ISTS and (b) a Forum of regulators comprising of CERC and SERCs
- SG to constitute a coordination forum consisting of chairperson of SERC and representatives of Gencos.& Transmission & distribution licensees
- Co-ordination Forum to ensure smooth and coordinated development power system in the state/ country

Transitional Provisions

- SEB shall be deemed to be STU for a period for one year of such earlier date as the SG may notify. By notification the SG may authorize the SEB to continue beyond one year.
- Agreements entered into under E(S) and ERC Act may continue for maximum 1 year
- CTU to operate RLDC and STUs to operate SLDCs till another govt. co. or authority is notified.

THE PROBLEM

INABILITY OF SEBs TO MEET CURRENT EXPENDITURE FROM CURRENT REVENUES

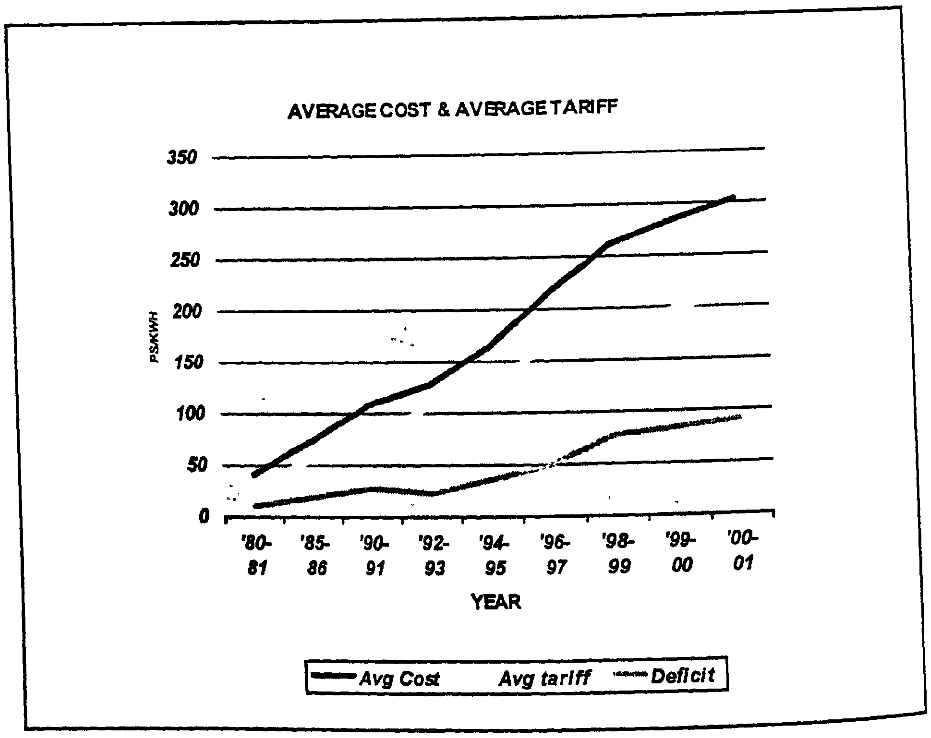
Mr R Ramanujam
October 16, 2001

LOSSES OF SEBs

	1996-97	97-98	98-99	99-2000	2000-01
Commercial Losses (without subsidy) (Rs. Cr)	-11305.00	-13963.00	-19972.00	-23028.00	-26013.00
Net Internal Resources (Rs. Cr)	-2090.70	-6209.00	-11401.70	-11531.60	-13092.50

AVERAGE COST OF POWER AND AVERAGE TARIFF (INDIA)

Year	Avg unit cost of supply (Paise)	Avg tariff per unit sale (paise)	Deficit per unit sale (paise)	Deficit as % of cost power
1980-81	41.9	32.3	9.6	22.9
1985-86	74.6	55.6	19.0	25.5
1990-91	108.6	81.8	26.8	24.7
1992-93	128.2	105.4	22.8	17.8
1994-95	163.4	128.0	35.4	21.7
1996-97	215.8	165.3	50.5	23.4
1998-99	262.9	185.5	77.4	29.4
1999-00 (prov)	283.7	199.0	84.7	29.9
2000-01 (RE)	303.9	212.0	91.9	30.2



WHAT CAUSES THE PROBLEM

- HIGH INPUT COSTS
- SUB- OPTIMAL UTILISATION OF CAPACITY
- IRRATIONAL TARIFFS
- HUGE T & D LOSSES
- POOR COLLECTION EFFICIENCY

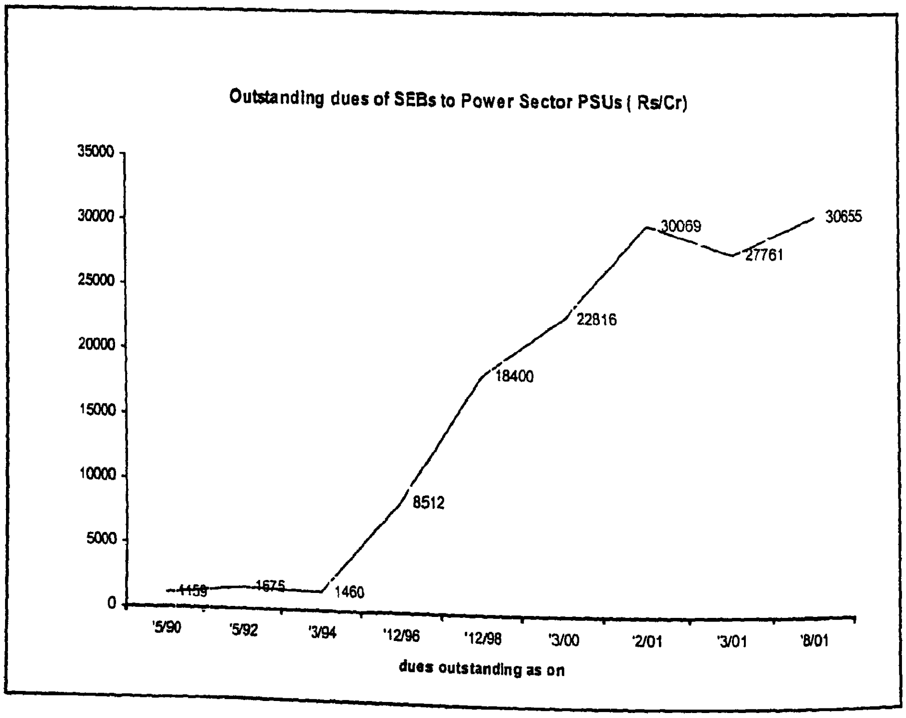
HOW LOSSES ARE FUNDED

- SUBVENTIONS FROM STATE GOVERNMENT
- BONDS & DEBENTURES OTHERWISE MEANT FOR CAPITAL EXPENDITURE
- DEFAULTING ON PAYMENTS TO SUPPLIERS OF POWER, FUEL AND EQUIPMENTS
- DEFAULTING ON SERVICING OF DEBTS FROM FIs
- DEFAULTING ON STATUTORY & OTHER DUES (?)

OUTSTANDING DUES OF SEBs TO POWER SECTOR PSUs

(Rs . Crores)

As on	Principal	Surcharge	Total
31.05.1990			1159
31.05.1992			1675
31.03.1994			1460
31.12.1996	4759	2753	8512
31.12.1998	10992	7408	18400
31.03.2000	13610	9206	22816
28.02.2001	18136	11933	30069
31.03.2001	15944	11817	27761
31.08.2001	18069	12586	30655



CPA RECOVERIES OF DUES AS ON 31/12/1996 (CPSUs of POWER , COAL , ATOMIC ENERGY , RAILWAYS AND BHEL)

(Rs / Crores)

Outstanding dues as on 31/12/1996	Recovered in 2000-2001	Recovered during 1997-2001	Balance
12612	1508	6079	6533

CPSU'S DUES AS ON 28/02/2001 (RS/CR)

DUES	NTPC	NHPC	NLC	NPC	NLC	NEEP CO
Principal	10987	1939	1955	771	765	1264
Surcharge	6057	1811	1357	772	246	1466
Total	17044	3750	3312	1543	1011	2730

CPSU'S DUES AS ON 28/02/2001 (RS/CR)

DUES	DVC	PGCIL	CIL	BTPS	RLYS	TOTAL
Principal	1264	1132	5222	880	812	25727
Surcharge	1466	302	3281	455	0	15746
Total	2730	1434	8503	1335	812	41473

FM's 1998 BUDGET SPEECH

"The outstanding dues from SEBs to major public sector undertakings such as NTPC and Coal India amount to about Rs. 10,000 Crore. These large outstanding dues are serious impediments to investment by these Public Sector Undertakings. The government will evolve a guarantee scheme to cover such dues. On the strength of such guarantees, the PSUs concerned will be able to raise resources either by securitizing these debts or directly entering the market for tapping resources. This would help these enterprises to raise resources to fund large projects in the power and coal sectors. The resulting investment will also boost industrial growth and investment through linkage effects."

WHY SECURITIZATION

ALTERNATIVES

- CASH PAYMENTS IN INSTALMENTS
- TAKE OVER OF ASSETS BY CPSUs
- ISSUE OF BONDS BY SEBs
- TAKE OVER OF LIABILITIES BY STATE GOVERNMENTS
- FULL OR PARTIAL WRITE OFF BY CPSUs

SECURITIZATION SCHEME OF JULY 2000

- SEBs TO ISSUE BONDS
- BONDS TO BE BACKED BY STATE GOVT GUARANTEES
- PROVISIONS IN STATE BUDGETS FOR PAYMENTS IN CASE OF DEFAULT
- FURTHER COMFORT FROM 15 % C.P.A.
- TAX - FREE STATUS FOR BONDS
- ONLY THE PRINCIPAL AMOUNT TO BE COVERED
- REFORM MILESTONES TO BE AGREED TO
- 105 % LC FOR CURRENT BILLING

RESPONSE OF STATES

- GRANT 100 % WAIVER OF SURCHARGE
- LC FOR 105 % NOT POSSIBLE
- PROVISION IN STATE BUDGET NOT POSSIBLE FOR A CONTINGENT LIABILITY
- CAN'T GENERATE SURPLUSES TO SERVICE THE BONDS
- 15 % CPA DEDUCTION MUST STOP

REASONS FOR POOR RESPONSE

- TAX FREE BONDS – NOT SUFFICIENTLY ATTRACTIVE
- PRESENTLY GETTING AWAY WITHOUT ANY PAYMENT SO , WHY PAY INTEREST ON BONDS
- ABSENCE OF COERCIVE PROVISIONS SUCH AS DEDUCTIONS BEYOND 15 % CPA
- 15 % CPA TO CONTINUE TO BE DEDUCTED TOWARDS SURCHARGE AS ONLY PRINCIPAL IS SECURITISED.
- QUALITY OF BONDS NOT BACKED BY 15% CPA – POOR, ILLIQUID
- LACK OF CLARITY ON REFORM PATH
- 105 % L.C. FOR CURRENT PAYMENTS –DIFFICULT, INVOLVE ADDITIONAL COSTS

CONCERNS OF CPSUs

- STATE GOVERNMENT GUARANTEE IS NO GUARANTEE AGAINST DEFAULTS
- ILLIQUID NATURE OF SECONDARY MARKET IN INDIA
- CUMBERSOME PROCESS OF INVOKING CPA BACK-UP
- INADEQUACY OF CPA BACK-UP AT 15%
- EVEN 15 % MAY NOT BE AVAILABLE IF RELEASED ALREADY TOWARDS SURCHARGE

ATTEMPT TO SALVAGE THE SCHEME

- FORMATION OF SPV
- FLOW OF 15 % CPA DEDUCTION INTO SPV ACCOUNT
- ISSUE OF BONDS BY SPV FOR AN AMOUNT THAT CAN BE SERVICED BY 15 % CPA

ADVANTAGES OF SPV

- HIGHEST CREDIT RATING FOR THE BONDS
- NO ADDITIONAL BURDEN ON SEBs / STATE GOVERNMENTS
- LIQUIDITY IMPROVEMENT FOR CPSUs

OBJECTIONS

- SHIFT OF ONUS OF SERVICING DEBT FROM STATE TO THE CENTRE
- WHAT SHOULD BE THE LAST RESORT BECOMES THE FIRST/ONLY RESORT
- REFORM NOT GUARANTEED

CM's CONFERENCE - 3/3/2001

RESOLUTION:

"An Expert Group would be set up to recommend one time *settlement of all* power sector past dues to CPSUs and dues from CPSUs to State Power Utilities. This would be linked to implementation of reforms with time-bound milestones.The Group will give its report within three weeks of its constitution"

APPROACH OF THE GROUP

- PROBLEM OF OUTSTANDINGS ATTRIBUTABLE TO UNVIABILITY OF CURRENT OPERATIONS
- REDUCTION OF T&D LOSSES, RATIONALISATION OF TARIFF, IMPROVEMENT IN COLLECTION EFFICIENCY AND TRANSAPARENT , TARGETTED SUBSIDIES WILL MAKE THE DIFFERENCE FOR THE SEBs
- PROBLEM OF OUTSTANDING DUES AN IMPEDIMENT TO REFORMS
- SETTEMENT DIRECTLY WITH SEBs WOULD RESULT IN ADDITIONAL BURDEN ON THEM IN FUTURE ; REGULATORS MAY NOT ALLOW SUCH PAST LIABILITIES INTO THE TARIFF

- STATE GOVERNMENTS BETTER PLACED TO TAKE ON THIS BURDEN, PERHAPS LEVY AN ELECTRICITY DUTY/ADDITIONAL DUTY IF NECESSARY WHICH WOULD BE IMMUNE TO LEGAL CHALLENGE
- CLEANING UP OF THE BALANCE SHEET OF SEBs WILL ENABLE THEM TO FOCUS ON CURRENT DEFICITS
- CPSUs' HEALTH CRITICAL FOR POWER SECTOR – THEY NOW PRODUCE 30 % OF THE POWER. COMPLETE WRITE-OFF THEREFORE NOT DESIRABLE
- CPSU s CAN AFFORD TO TAKE A HIT ON SURCHARGE AS THIS IS NOT INCLUDED IN THEIR BALANCE-SHEET

- CARRYING COSTS OF RECEIVABLES SHOULD BE KEPT IN VIEW IN DETERMINING EXTENT OF RELIEF ON SURCHARGE
- SETTLEMENT SHOULD BE CONFINED TO OVERDUES ON CURRENT ACCOUNT – MORAL HAZARD IN COMPROMISING CAPITAL PAYMENTS
- REFORM MILESTONES TO BE PRESCRIBED TO PREVENT RECURRENCE OF THE PROBLEM
- INCENTIVES / REWARDS FOR ACHIEVEMENT OF SUCH MILESTONES
- DETERRENT ACTION AGAINST FUTURE DEFAULTS

RECOMMENDATIONS OF THE EXPERT GROUP

SECURITIZATION OF PAST DUES :

- CUT OFF DATE : 1.3.2001
- NTPC, NHPC, PGCIL, CIL, NPC, NLC, NEEPCO, DVC & RAILWAYS' DUES INCLUDED
- REC, PFC & BHEL DUES ARE ON CAPITAL ACCOUNT, HENCE EXCLUDED
- SIMILAR BILATERAL SETTLEMENT WITH REC AT THE DISCRETION OF CENTRAL GOVERNMENT
- OPTION TO CONVERT EXISTING BONDS ISSUED BY SEBs AFTER 1.3.1998 .

PARTIAL WRITE- OFF

- WAIVER OF 50 % OF SURCHARGE/ INTEREST - RS 7873 CRORES

SECURITISATION OF DUES

- 15 YEARS BONDS TO BE ISSUED BY STATE GOVERNMENTS TO THE CPU'S
- REPAYABLE IN 20 EQUAL SEMI-ANNUAL INSTALMENTS FROM 01.10.2006
- FIVE YEAR MORATORIUM OF PRINCIPAL REPAYMENT
- LOCK-IN : 10 % BONDS TO BE RELEASED IN SECONDARY MARKET EACH YEAR
- BONDS TO BE TREATED AS MARKET BORROWINGS OF STATE GOVERNMENTS , TO BE MANAGED BY RBI

INTEREST

- NOMINAL INTEREST OF 8.5 % P.A. TO BE TAX-FREE
- PAYABLE ONCE EVERY SIX MONTHS FROM **31 / 08 / 2001**

DISPUTED AMOUNTS

- DISPUTES TO BE SETTLED AS PER DUE PROCESS OF LAW INCLUDING ARBITRATION
- INTEREST ON AWARD AMOUNTS : 12 % UPTO THE DATE OF ACTUAL SETTLEMENT

B: PAYMENT OF CURRENT DUES

TIME LIMIT FOR PAYMENT:

- PAYMENT OF CURRENT BILLS WITHIN 60 DAYS

LETTER OF CREDIT

- IRREVOCABLE LC EQUAL TO 105 % OF AVERAGE MONTHLY BILLING
- LC TO BE OPENED BEFORE 31.10.2001
- DEFAULT TO CAUSE 2.5 % REDUCTION IN SUPPLIES
- 2 % CASH INCENTIVE ON BONDS IF LC OPENED BY 31.7.2001 AND MAINTAINED UPTO 31/12/2001 TO COST RS 700 CR

INTEREST ON DELAYED PAYMENTS

- 15 % P.A. COMPOUNDED ON QUARTERLY BASIS

PENAL PROVISIONS

REDUCTION IN SUPPLIES:

5 % , 10 % AND 15 % CUT IN SUPPLIES FOR PAYMENT DEFAULT AFTER 60 , 75 AND 90 DAYS OF BILLING RESPECTIVELY

RECOVERY OF OVERDUES FROM STATEGOVERNMENTS

OVERDUES OF OVER 90 DAYS TO BE ADJUSTED BY MOF

SUSPENSION OF APDP

- RELEASE OF APDP TO BE WITHHELD ON PAYMENT DEFAULT OF 90 DAYS

DISPUTED AMOUNTS:

- 95 % OF DISPUTED AMOUNT TO BE PAID UPFRONT PENDING FINAL SETTLEMENT
- THE AMOUNT AWARDED SHALL CARRY INTEREST @ 15 % P.A. FROM THE DUE DATE

C: REFORM BASED MILESTONES

MOUs

- STATES TO SIGN REFORM BASED MOUs WITH MOP BEFORE SETTLEMENT OF DUES
- MOUs OF MOF TO BE ALSO BINDING

SERCs

- SERCs TO BE SET IN PLACE BY 1.9.2001
- FILE TARIFF PETITION BY 31.10.2001
- IMPLEMENT TARIFF ORDER OF SERC WITHIN 2 MONTHS

OTHER MILESTONES

- ENERGY AUDIT AT 11 KV FEEDERS BY 31.12.2002
- METERING OF DISTRIBUTION FEEDERS BY 31.12.2002
- AVERAGE COST OF POWER AND CASH REALISATION TO MATCH WITHIN 5 YEARS

REVIEW OF PERFORMANCE

- REVIEW OF PERFORMANCE MILESTONES EVERY SIX MONTHS BY A PANEL
- DEFAULT TO ATTRACT REDUCTION IN DISCRETIONARY POWER (15 %) AND APDP

INCENTIVE

- INCENTIVE : 4 % ON BOND AMOUNT FOR FOR STATES THAT DO NOT DEFAULT - TO COST RS 5600 CR
- APPLICABLE FOR 4 YEARS ONLY

D: OTHER PROVISIONS

REWARD FOR BETTER MANAGED SEBS

- SEBs WITH DUES LESS THAN 3 MONTHS OF BILLING TO QUALIFY
- BONDS FOR UPTO ONE MONTH'S BILLING – FOR UPGRADATION OF NETWORK ETC.

NON-CONFORMING STATES

- STATES THAT DO NOT CONSENT WILL NOT GET DISCRETIONARY POWER AND APDP
- REDUCTION IN SUPPLY OF POWER , COAL ETC IF OVERDUES EXCEED RS 50 CRORE
- MAY JOIN LATER ON PAYMENT OF 12 % INTEREST UPTO THE DATE OF JOINING

ENTRY INTO FORCE

SCHEME TO BE EFFECTIVE ONLY AFTER HALF OF THE STATES WITH ANNUAL CPSU BILLING OF OVER RS 500 Cr CONSENT

TRANSPARENCY

- SCHEME TO BE IMPLEMENTED TRANSPARENTLY
- MOP TO REVIEW AND PLACE A REPORT ON THE WEBSITE EVERY QUARTER

DISCUSSIONS IN THE HIGH LEVEL EMPOWERED GROUP

- WAIVE 100 % OF SURCHARGE
- ALLOW SEBs TO ISSUE BONDS WITH STATE GOVERNMENT GUARANTEE
- GRANT MORATORIUM ON PRINCIPAL AS WELL AS INTEREST
- SECURITISE PART OF CURRENT PAYMENTS TILL COMPLETE TURNAROUND
- SET-OFF CPSU'S OVERDUES TOWARDS SEBs

- WRITE OFF REC LOANS AS THEY WERE FOR A SOCIAL CAUSE
- ROLL BACK REVISION OF TARIFF NORMS
    - 16 % ROE
    - DEPRECIATION
    - INCOME TAX PASS THROUGH
- COMPLY WITH CERC ORDERS
- SET UP REGULATORY AUTHORITY FOR COAL

BENEFITS AS RECOMMENDED VIS-A-VIS DEMAND FOR 100 % WAIVER OF SURCHARGE

- THE TOTAL DUES OF SEBs TO CPSUs OUTSTANDING AS ON 28/02/2001WERE RS 41477 Cr OUT OF WHICH THE SURCHARGE WAS Rs 15750 Cr.
- THE TOTAL BENEFITS ACCRUING TO THE SEBs AS RECOMMENDED WORKS OUT Rs 23189 Cr.
- THE BENEFIT OF Rs 23189 Cr IS MORE THAN THE SURCHARGE AMOUNT OF Rs 15750 Cr.

ONE TIME SETTLEMENT OF SEB DUES

			BENEFIT TO THE SEBs / STATES (RS / CR)							
			WAIVER @ 60 % OF SURCHARGE		INCENTIVES FOR MILESTONES		DIFFERENCE BETWEEN FACEVALUE OF THE BINDS AND NPV OF INTEREST AND REPAYMENTS @ 13 % DISCOUNT	CONVERSION OF OLD BONDS		TOTAL
SEB	DUES	AMT	AMT	NPV	AMT	NPV	NPV	AMT	NPV	NPV
TOTAL	PRINCIPAL	25727	9450	9450	6726	5195	8222	480	322	23189
	SURCHARGE	15750								
	TOTAL	41477								

OUTSTANDING DUES OF SEBs ON CPSUs
Rs/ Cr

SL	CPSUS	MPEB			HPSEB		
NO		PRIN	INTT	TOTAL	PRIN	INTT	TOTAL
1	NHPC	0 00	0 00	0 00	52 55	198 80	251 35
2	N TEX MILLS(NTC)	19 23	23 41	42 64	0 00	0 00	0 00
3	RAILWAY TRACTION	185 88	41 52	227 40	0 00	0 00	0 00
4	BALCO	4 17	0 00	4 17	0 00	0 00	0 00
5	NEPA MILLS	15 11	0 00	15 11	0 00	0 00	0 00
6	CCI	146 33	91 61	237 94	0 00	0 00	0 00
7	FCIL	0 00	0 00	0 00	0 00	0 00	0 00
8	IDPL,HYDERABAD	0 00	0 00	0 00	0 00	0 00	0 00
9	BHEL	0 00	0 00	0 00	0 00	0 00	0 00
10	BHILAI STEEL PLANT	144 34	108 78	253 12	0 00	0 00	0 00
11	COAL MINES	0 55	0 00	0 55	0 00	0 00	0 00
12	OTHER DEPARTMENTS	3 27	0 92	4 19	0 00	0 00	0 00
13	BHARAT GOLD MINES	0 00	0 00	0 00	0 00	0 00	0 00
14	VI &S LTD	0 00	0 00	0 00	0 00	0 00	0 00
	TOTAL	518 88	266 24	785 12	52 55	198 80	251 35

OUTSTANDING DUES OF SEBs ON CPSUs
Rs/ Cr

SL	CPSUS	APSEB			KPTC		
NO		PRIN	INTT	TOTAL	PRIN	INTT	TOTAL
1	NHPC	0 00	0 00	0 00	0 00	0 00	0 00
2	N TEX MILLS(NTC)	0 00	0 00	0 00	0 00	0 00	0 00
3	RAILWAY TRACTION	0 00	0 00	0 00	0 00	0 00	0 00
4	BALCO	0 00	0 00	0 00	0 00	0 00	0 00
5	NEPA MILLS	0 00	0 00	0 00	0 00	0 00	0 00
6	CCI	19 56	0 00	19 56	4 65	0 00	4 65
7	FCIL	28 44	0 00	28 44	0 00	0 00	0 00
8	IDPL,HYDERABAD	30 02	0 00	30 02	0 00	0 00	0 00
9	BHEL	1 71	0 00	1 71	0 00	0 00	0 00
10	BHILAI STEEL PLANT	0 00	0 00	0 00	0 00	0 00	0 00
11	COAL MINES	0 00	0 00	0 00	0 00	0 00	0 00
12	OTHER DEPTS	0 00	0 00	0 00	0 00	0 00	0 00
13	BHARAT GOLD MINES	1 40	0 00	1 40	46 18	18 42	64 60
14	VI &S LTD	0 00	0 00	0 00	11 10	0 00	11 10
	TOTAL	81 13	0	81 13	61 93	18 42	80 35

OUTSTANDING DUES OF SEBs ON CPSUs

Rs/ Cr

SL NO	CPSUS		RSEB	
		PRIN	INTT	TOTAL
1	NHPC	0 00	0 00	0 00
2	N TEX MILLS(NTC)	0 47	0 00	0 47
3	RAILWAY TRACTION	7 76	0 00	7 76
4	BALCO	0 00	0 00	0 00
5	NEPA MILLS	0 00	0 00	0 00
6	CCI	0 00	0 00	0 00
7	FCIL	0 00	0 00	0 00
8	IDPL,HYDERABAD	0 00	0 00	0 00
9	BHEL	0 00	0 00	0 00
10	BHILAI STEEL PLANT	0 00	0 00	0 00
11	COAL MINES	0 00	0 00	0 00
12	OTHER DEPARTMENTS	0 00	0 00	0 00
13	BHARAT GOLD MINES	0 00	0 00	0 00
14	VI &S LTD	0 00	0 00	0 00
	TOTAL	8 23	0 00	8 23

OUTSTANDING DUES OF SEBs ON CPSUs

Rs/ Cr

S.NO	SEB	AMOUNT	AS ON
1	MPEB	785.12	31/01/2001
2	HPSEB	251.35	28/02/2001
3	APSEB	81.13	28/01/2001
4	KPTCL	80.35	21/12/2000
5	RSEB	8.23	31/01/2001

IMPACT OF REVISION OF TARIFF NORMS ON PER UNIT TARIFF

- INCREASE IN ROE (RETURN ON EQUITY) FROM 12 % TO 16 % IS 4.38 Ps/ KWH
- INCREASE IN DEPRECIATION RATE FROM 5.06% TO 7.84 % ON PRE-1992 INVESTMENTS IS 4.27 Ps / KWH
- INCOME TAX PASS-THROUGH

1997-98	8.73 PS /KWH
1998-99	12.53 PS/KWH
1999-00	7.36 PS/KWH
2000-01	8.32 PS /KWH

THANK YOU

Power Play in California

Prabir Purkayastha

California: Essential Facts

- The summer of 2000 saw blackouts and electricity emergencies for the first time in 50 years
- The wholesale electricity cost jumped from $7.4 billion in 1999 to $27 billion in 2000
- Rate increase of 80% or more for consumers
- The two major utilities - PG&E and SC&E -- are bankrupt

Leaders on Electricity Markets Then and Now

- On Sept. 23, 1996, Pat Wilson, then Governor, on signing the new deregulation Bill "we've pulled the plug on another outdated monopoly, and replaced it with the promise of a new era of competition."
- State senator Jim Brulte, the Bill's author "one of the most far-reaching and forward thinking pieces of legislation."

Leaders on Electricity Markets Then and Now (Contd.)

- The US Energy Secretary, Bill Richardson, ".... California's electricity market has become dysfunctional."
- California Governor, Gray Davis "My friends, electricity is not an exotic commodity like pork bellies, to be traded in the chaotic equivalent of a futures market; electricity is a basic necessity of life."

California Electricity Scenario: Before Deregulation

- Three major utilities: pacific gas & electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E)
- A number of green plants from which the utilities were forced to buy
- California Public Utilities Commission (CPUC) regulated the sector on a cost plus basis

Demand for Deregulation

- The cost of power was higher than other states due to:
  - Higher cost of green power
  - Higher cost of nuclear power
  - Low international oil and gas prices
- Large energy guzzling industries were demanding lower cost power
- California had a reserve margin of 25-30% against an US norm of 15%

Alliance for Deregulation

- CPUC declared the regulated system as "fragmented, outdated, arcane and unjustifiably complex"
- Large energy consumers lobbied for deregulation
- The three major utilities agreed to deregulation as long as they could recover their stranded costs of the nukes
- Pat Wilson and the Republicans running the state were market fundamentalist

---

Key Elements of Deregulation

- The utilities shed all their generation: unbundled generation from transmission and distribution
- A California Power Exchange (Cal PX) -- on the pattern of a Stock Exchange – was created
- For real time operation of the Grid, a California Independent System Operator (Cal ISO) was created

The Key Elements of Deregulation (Contd.)

- Cal PX was the spot market where power was bought and sold for the next day
- Cal ISO was responsible for the grid: despatches, load shedding, etc.
- Cal ISO also bought power if required in the real time market to ensure grid stability
- Cal PX and Cal ISO were regulated by FERC and not CPUC

The Rate Freeze

- In order to get consumers to consent to deregulation a rate cut of 10% was agreed
- To recover sunk costs of the nukes, it was agreed that
  - The subscribers would pay for $7 billion that the utilities would release as bonds
  - A rate freeze till march 2002 or till the utilities cleared their debt
- The rate freeze was primarily for protecting the utilities

Before the Summer of 2000

- For the first two years, deregulation seemed to work
- Prices fell
- Sale of generating plants led to large cash surplus with the utilities
- Utilities set up independent companies that were generating companies and were not considered a part of the parent companies

The Summer of 2000

- The markets collapsed in the summer of 2000
- There was a shortage: demand outstripping supply in the spot market
- The Cal ISO, expected to step in only rarely, bought power at very high prices in the real time power market
- Prices went up by 7-10 times in times of crisis

San Diego: the Sign of Things to Come

- SDG&E that supplies San Diego area had paid off its debt and out of the rate freeze
- The increase in average bill was 182%
- The outcry forced a rate cap on SDG&E
- It became clear that if the rate freeze was not in operation, consumers in other areas would have faced similar increases

---

What Led to the Crisis?

- Two sets of issues: physical and economic
- Physical causes were
  - Higher than usual summer temperatures
  - Lack of rainfall reducing hydropower output in the north west USA
  - Outages in power plants
- Margins came down to less than 3.5% in summer

What Led to the Crisis? (Contd.)

- The physical causes can explain the lack of reserve and rolling blackouts but not price rise
- The prices rose as players quoted less power in the spot market leading to shortages – market power
- The Cal ISO was then forced to buy power at a higher rate in the real time market
- Interestingly prices did not come down even after summer or on Sundays when demand was much lower
- Gas prices also rose increasing the cost of power

Serious Market Power Problems

- Market power is generally defined as a firm's capability to profitably raise the price above competitive levels for a significant period of time
- Practical monitoring index: price-cost mark-up — market clearing price above system marginal cost
- Two ways to exercise market power: economic withholding and physical withholding. All market power bidding strategies will be carried out in one of these forms
- Economic withholding
  - Submit bids at prices above producer's marginal cost
  - Most often observed in CA ISO real time market
- Physical withholding
  - Restrict output or withhold capacity from bidding into market
  - Most serious problem in period of tight supply

Cal ISO Conclusions

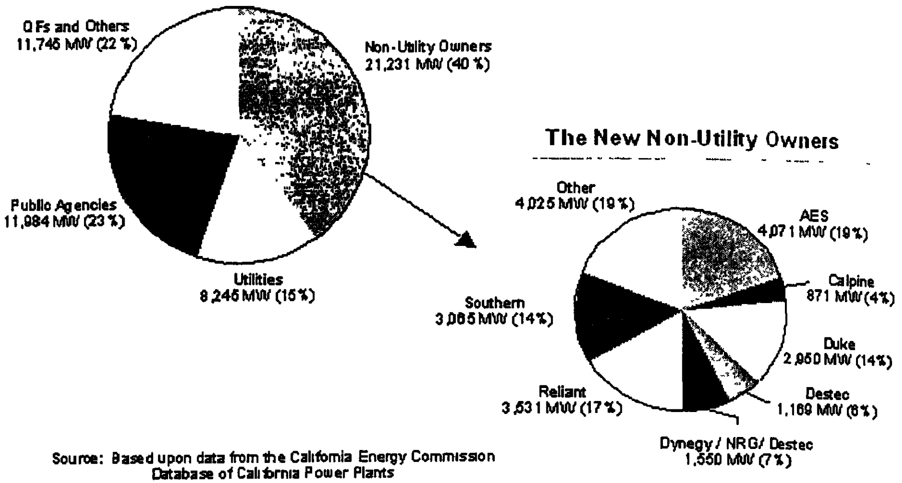
- Astronomical mark-up after accounting for scarcity: $6.2 billion (plus allowance for scarcity $0.6 billion) for 11 months from April 2000 to Feb. 2001
- $6.8 billion is enough money to build 13,000 MW of new power or 26 new combined cycle power plants

---

How High Was the Summer Peak?

- The Kahn-Lynch report shows that the peak energy and the peak MW was higher in 1999 than in 2000
- Mckinsey and Kahn-Lynch report computes that the gas price increase can explain only 1/3 to 1/2 of electricity price rise
- Kahn-Lynch hold the generators used market power and economic withholding to game the market
- Cal ISO study: 80% transactions by sellers cartel show overcharging

Who Owns Generation In California?



Source: Based upon data from the California Energy Commission
Database of California Power Plants
(http://www.energy.ca.gov/database/index.html#powerplants)

Californians Outside Crisis

- One set of consumers were free from crisis
- 30 publicly owned utilities -- the municipal authorities of Sacramento, Los Angeles, etc. with 23% of generating capacity chose to stay out of deregulation
- Their consumers faced no increase
- These utilities even made profits out of the California crisis

Who Gained and Who Lost?

- The gainers
    - The six major generators: duke, Enron, Mirant, Reliant and Williams (mostly Texas based)
    - In the third quarter of 2000, these six increased their average profits by 376%
    - The independent subsidiaries that California utilities have set-up and ring fenced their assets
    - Cal ISO study: Californian consumers overcharged by $6.2 billion

Who Gained and Who Lost? (Contd.)

- The losers
    - All consumers, particularly small consumers who never asked for deregulation
    - The shareholders of the utilities: PG&E has filed for bankruptcy under chapter 11 and SCE has worked out a deal but will not pay dividend for the next three years
    - The California taxpayers whose budget surplus disappeared as department of water bought power to bail out the bankrupt utilities

Market Myths

- Market fundamentalists claim deregulation and markets have not failed
- They argue the California crisis is due to
  - The greens not letting any new plants to be built for 12 years
  - Market not allowed full play: by price caps, demand was not reduced allowing crisis to continue
  - Complex market rules led to its failure

Why No New Plants

- The reality is that the California utilities thought that they had surplus power till 2005
- In 1994 SCE told CPUC that its estimates were wrong and California faced an energy glut
- Once the regulatory regime was changing, investors wanted to wait and watch before investing in new plants

Can Price Control Demand?

- In the short run, there are limits to pricing controlling demand
- It can induce behavioural conservation: turning the lights off when leaving the room/house
- Major conservation measures are energy efficient appliances and take longer time to cut in
- Price induced conservation is therefore of limited value

If Shortages Are Artificial?

- No energy conservation works if power supplies can be withheld
- California was short of power when summer peak was about 52.7 GW (16/08/00) and still short of power when demand was 34.4 GW (8/12/00)
- As long as there are a few players that can create artificial shortages, demand change has little impact

Failing Electricity Markets

- Dr. Mark N. Cooper, Director Research, Consumer Federation of America "judging market performance by the ability to provide consumers with a choice of high quality products at stable, reasonable prices, the restructured electricity market is failing from coast-to-coast."

Why Do Electricity Markets Behave Differently?

- Short-term supply responses are not possible as electricity cannot be stored
- Significant additions to supply still require substantial lead times
- Competition reduces the incentive for market participants to cooperate and maintain grid stability
- No one has an interest in building excess capacity

Some Lessons

- Market failure hurts the consumer more than a bad regulator
- The state cannot abandon the consumer in such a vital sector
- Electricity markets are different as
  - They have to be always in balance: no storage
  - There is much lower elasticity of demand
  - A few players can "game" the market
  - Small consumers get no benefit of lower costs but will bear the major cost of failure

---

Electricity: Essential Services

> "Believing electricity is just another commodity is like believing oxygen is just another gas"

Michael Shames, Ex. Dir., UCAN

Reforming Distribution Business

Presentation at IAS Officers' Training
organised by TERI

October 17, 2001 **P.Neogi**

Index

- Introduction
- Drivers for Reform
- Pre-Transition Issues
- Re-engineering Distribution
- Regulatory Challenges
- Service Standards
- Building Legitimacy
- Policy Imperatives

Noida Power Company

Background

- ✓ Joint venture between Greater Noida Industrial Development Authority and RPG Group
- ✓ Licensee in terms of Section 3(1) of the Indian Electricity Act, 1910
- ✓ Buys power from UPPCL and undertakes distribution with own network
- ✓ First experiment of privatisation of SEB distribution, having started in December 1993

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Noida Power Company (Contd..)

Financial Highlights

- ✓ Power purchase price adjudicated by State Regulatory Commission, retail tariff same as of U.P.
- ✓ Accumulated Profit upto FY 2000-01 Rs.60m, Net Worth Rs.140m, Equity Rs.92m
- ✓ Sales in FY 2000-01 Rs.525m, Demand 35 MVA, Debt / Equity Ratio 30:70
- ✓ Assets Rs.345m in 2000-01 from Rs.100m inherited

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Drivers for Reform

Privatisation in Developed Countries

- **Lessons**
  - ✓ Driven by a free market economy to establish competitive pricing
  - ✓ Concept extended by unbundling of distribution & supply business to reinforce economic pricing
  - ✓ Move to privatisation was easier because of good operational track record & efficient functioning
  - ✓ Circumstances / structural conditions in developing countries fundamentally different — case for functional improvements & financial turn-around

Privatisation of Distribution

- **Generic Factors**
  - ✓ New investments for system upgradation
  - ✓ New technology for process improvement
  - ✓ Modern management practices for commercial orientation
- **Objectives**
  - ✓ SBUs to focus on metering, billing, collection and consumer service
  - ✓ Release public funds for social spending and facilitate economic reforms

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Pre-Transition Issues

The Vicious Cycle

- **Bugs & Bites**
  - ✓ Prospect of reasonable profit often too distant
  - ✓ Line of credit difficult to establish
  - ✓ Inflexible labour, doubtful ownership rights
  - ✓ Predictability of earnings, uncertain T&D losses
  - ✓ Turnaround not without reinventing the wheel

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The Way Forward

- **Enablers**
  - ✓ Eliminating data gaps in billing, receivables, assets
  - ✓ Restructuring capital for leveraging debt / equity ratio
  - ✓ Addressing past losses, also liabilities not provided for
  - ✓ Avoiding mid-course changes – 'speed drives value'
  - ✓ Reorienting workforce, focussing on redeployment

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Re-engineering Distribution

Building Blocks

- **Mapping Processes**
  - ✓ Ensure seamless flow of data
  - ✓ Define measurement standards
  - ✓ Develop IT-driven applications
  - ✓ Develop fact-based management to
    - ➢ protect revenue
    - ➢ improve service

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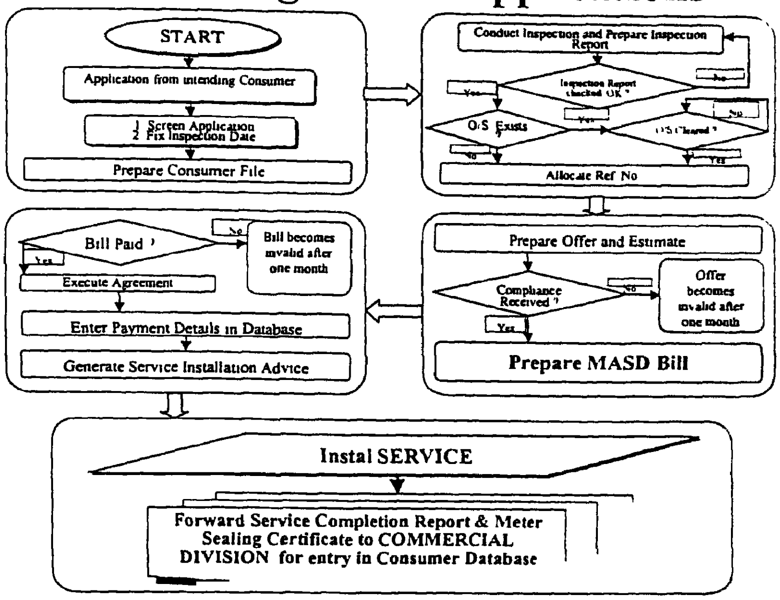
Processing of New Applications


START
Application from intending Consumer
1 Screen Application
2 Fix Inspection Date
Prepare Consumer File
Conduct Inspection and Prepare Inspection Report
Inspection Report checked OK ?
Yes
No
O/S Exists ?
Yes
O/S Cleared ?
No
No
Yes
Allocate Ref No
Prepare Offer and Estimate
Compliance Received ?
No
Offer becomes invalid after one month
Yes
Prepare MASD Bill
Bill Paid ?
No
Bill becomes invalid after one month
Yes
Execute Agreement
Enter Payment Details in Database
Generate Service Installation Advice
Instal SERVICE
Forward Service Completion Report & Meter Sealing Certificate to COMMERCIAL DIVISION for entry in Consumer Database

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Cycle Time Reduction

- **Before**

Application Form – Inspection – Offer – Accepted by Consumer – **Bill**

- **After**
  - ✓ **Case A :** New Township

    Application Form → **Bill**
  - ✓ **Case B :** Other Areas

    Application Form → **Inspection** → **Offer-cum-Bill**

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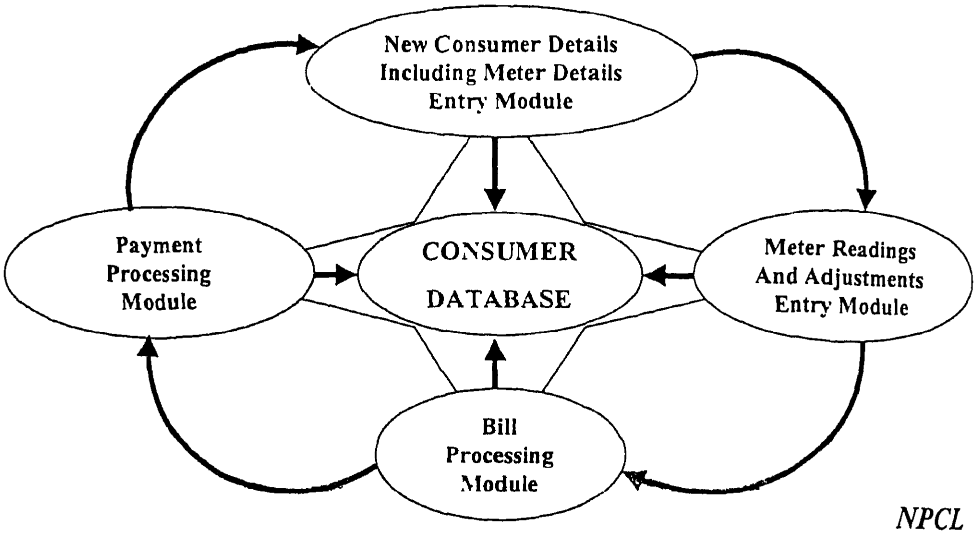
Schematic view of Billing System



New Consumer Details Including Meter Details Entry Module

Payment Processing Module

CONSUMER DATABASE

Meter Readings And Adjustments Entry Module

Bill Processing Module

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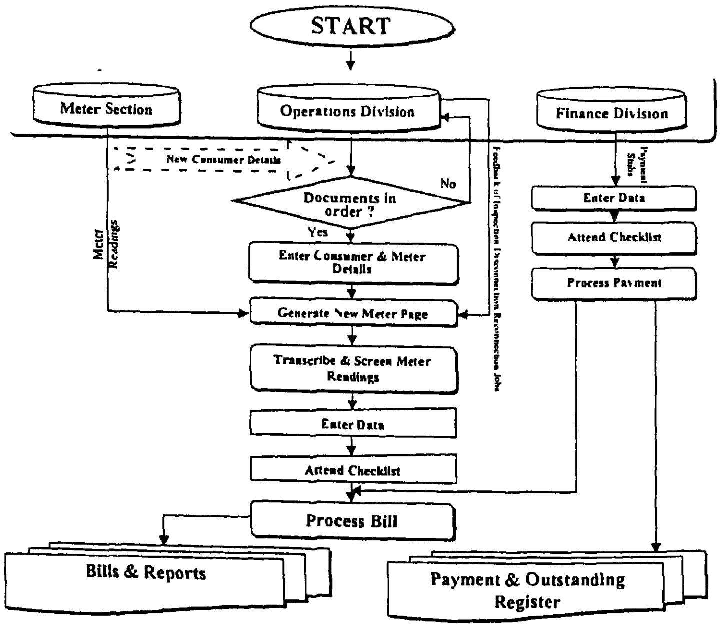
Billing System



START

Meter Section

Operations Division

Finance Division

New Consumer Details

Documents in order ?

No

Yes

Meter Readings

Enter Consumer & Meter Details

Generate New Meter Page

Feedback of Inspection Disconnection Reconnection Jobs

Transcribe & Screen Meter Readings

Enter Data

Attend Checklist

Payment Stubs

Enter Data

Attend Checklist

Process Payment

Process Bill

Bills & Reports

Payment & Outstanding Register

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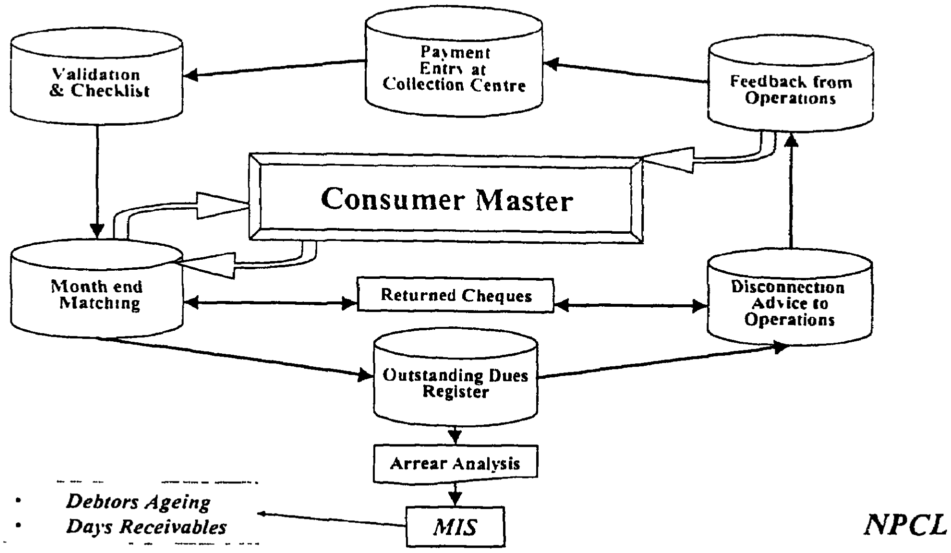
Payment Follow-Through



Payment Entry at Collection Centre

Validation & Checklist

Feedback from Operations

Consumer Master

Month end Matching

Returned Cheques

Disconnection Advice to Operations

Outstanding Dues Register

Arrear Analysis

MIS

- *Debtors Ageing*
- *Days Receivables*

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Bar Code System

- Payment details optically scanned for viewing on monitor and checked for consistency
- No manual entries, hence accurate posting, leading to faster disposal of queues
- On-line transfer of daily return through LAN/WAN, alternatively through Floppy Diskettes for updating / matching of payment records
- Entries made by Finance Division as per lodgements

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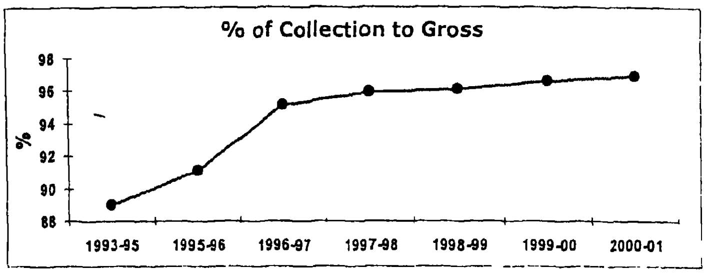
Collection Efficiency

Rs. In Lac

	1993-94 & 1994-95	1995-96	1996-97	1997-98	1998-99	1999-00	2000-01
Gross Billing	2400 17	2495 01	3189 75	4302 99	4821 15	4931 16	5405 63
Collection	2146.14	2314 79	3226 11	4192 89	4664	4841 92	5300 49
% of Collection to Gross	89	91 10	95 10	95 90	96 10	96 60	96 88



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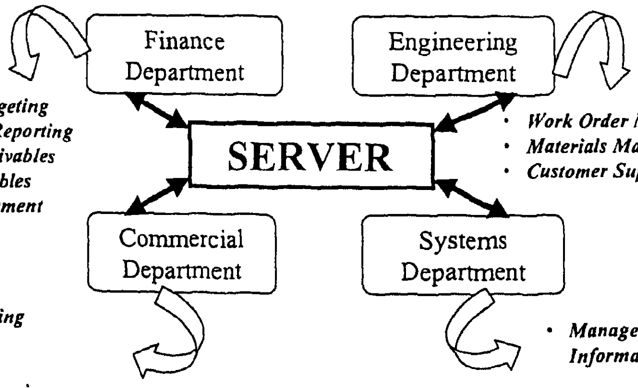
Integrated IT Approach



Finance Department

Engineering Department

SERVER

Commercial Department

Systems Department

- *Financial Budgeting*
- *Management Reporting*
- *Accounts Receivables*
- *Accounts Payables*
- *Assets Management*

- *Work Order Monitoring*
- *Materials Management*
- *Customer Support*

- *Meter Reading*
- *Billing*
- *Collection*
- *Customer Service*

- *Management Information System*

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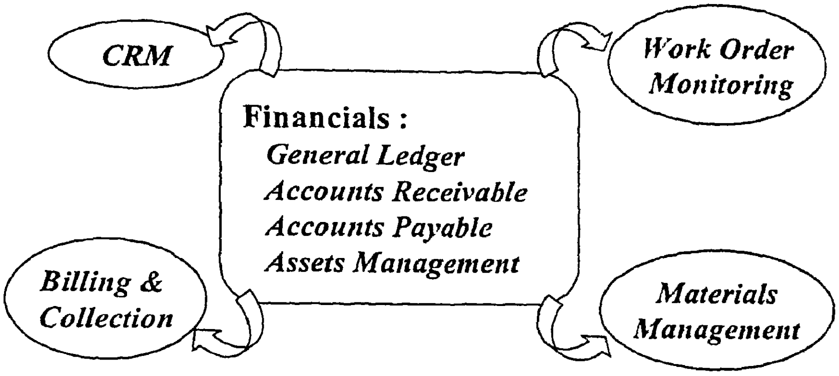
Integrated IT Approach (Contd..)

- **Interactive Modules**



CRM

Financials :

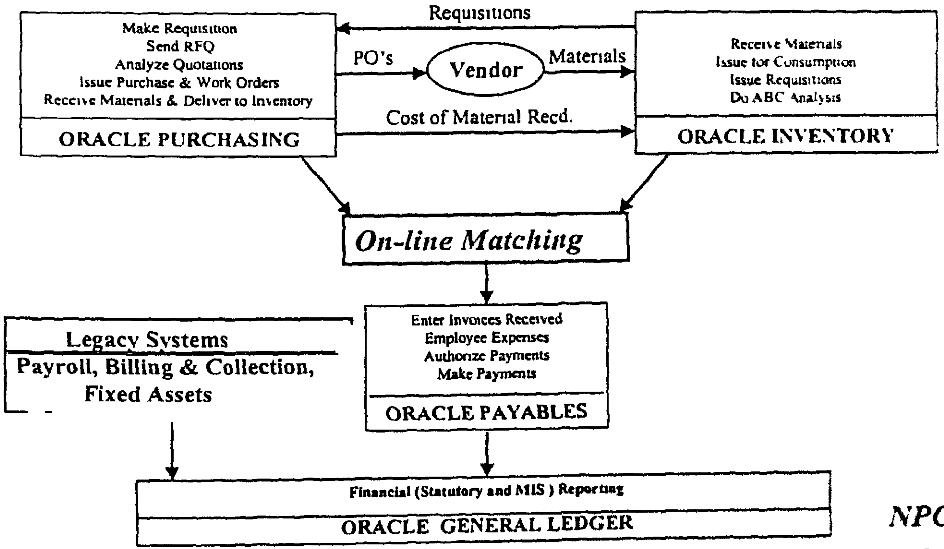
General Ledger
Accounts Receivable
Accounts Payable
Assets Management

Work Order Monitoring

Billing & Collection

Materials Management

Financial and Materials Management



Make Requisition
Send RFQ
Analyze Quotations
Issue Purchase & Work Orders
Receive Materials & Deliver to Inventory

ORACLE PURCHASING

Requisitions

PO's

Vendor

Materials

Cost of Material Recd.

Receive Materials
Issue for Consumption
Issue Requisitions
Do ABC Analysis

ORACLE INVENTORY

On-line Matching

Legacy Systems

Payroll, Billing & Collection,
Fixed Assets

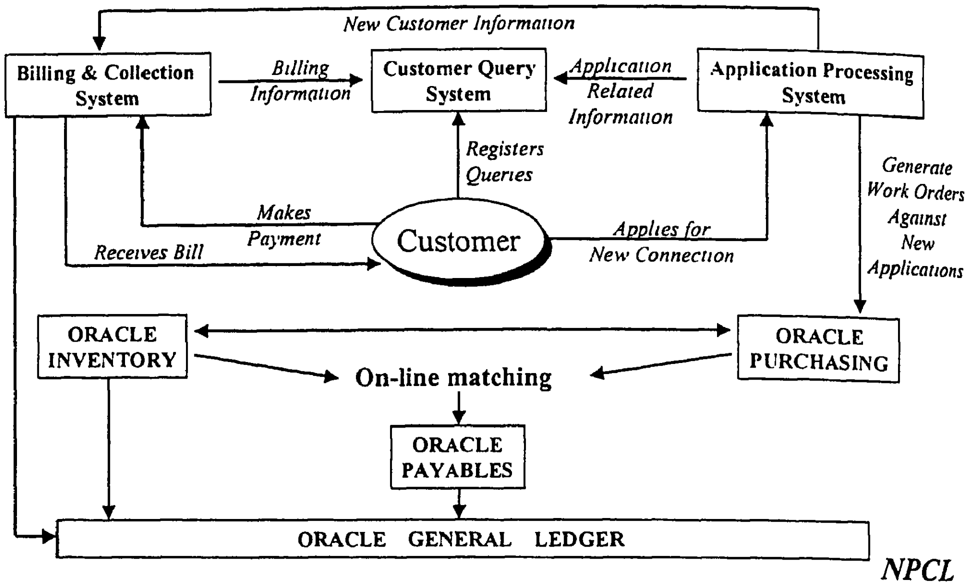
Enter Invoices Received
Employee Expenses
Authorize Payments
Make Payments

ORACLE PAYABLES

Financial (Statutory and MIS) Reporting

ORACLE GENERAL LEDGER

Integration of Consumer Billing & Financial Management



New Customer Information

Billing & Collection System

Billing Information

Customer Query System

Application Related Information

Application Processing System

Registers Queries

Makes Payment

Receives Bill

Customer

Applies for New Connection

Generate Work Orders Against New Applications

ORACLE INVENTORY

On-line matching

ORACLE PURCHASING

ORACLE PAYABLES

ORACLE GENERAL LEDGER

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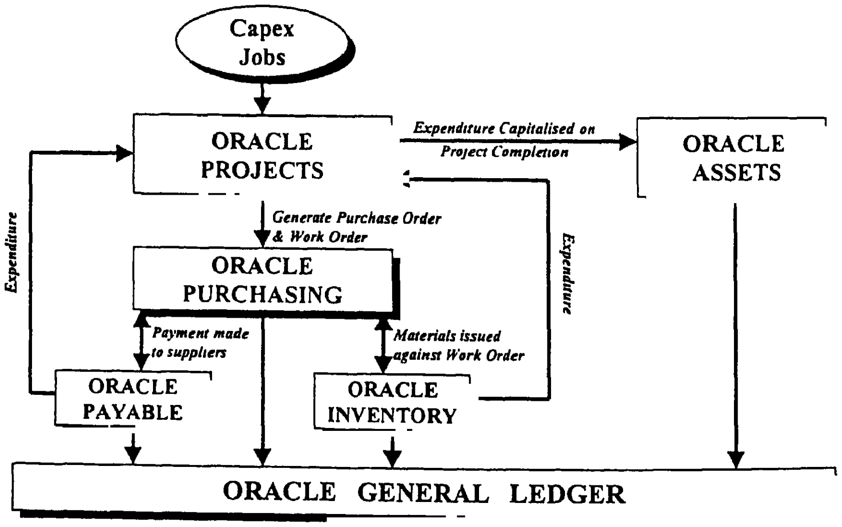
On-line Updating of Fixed Assets Register



Capex Jobs

ORACLE PROJECTS

Expenditure Capitalised on Project Completion

ORACLE ASSETS

Generate Purchase Order & Work Order

ORACLE PURCHASING

Expenditure

Expenditure

Payment made to suppliers

Materials issued against Work Order

ORACLE PAYABLE

ORACLE INVENTORY

ORACLE GENERAL LEDGER

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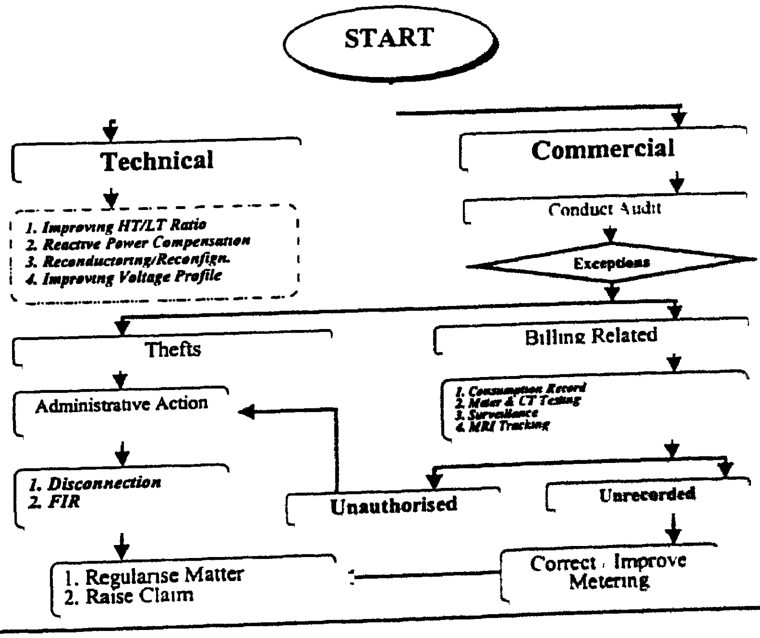
Building Blocks

- **Energy Accounting**
  - ✓ Organise loss control drive
  - ✓ Orchestrate loss minimisation plan
  - ✓ Use metering as analytical tool
  - ✓ Develop 'Before & After' scenario

Loss Control Activity



START

Technical

1. Improving HT/LT Ratio
2. Reactive Power Compensation
3. Reconductoring/Reconfign.
4. Improving Voltage Profile

Commercial

Conduct Audit

Exceptions

Thefts

Administrative Action

1. Disconnection
2. FIR

1. Regularise Matter
2. Raise Claim

Billing Related

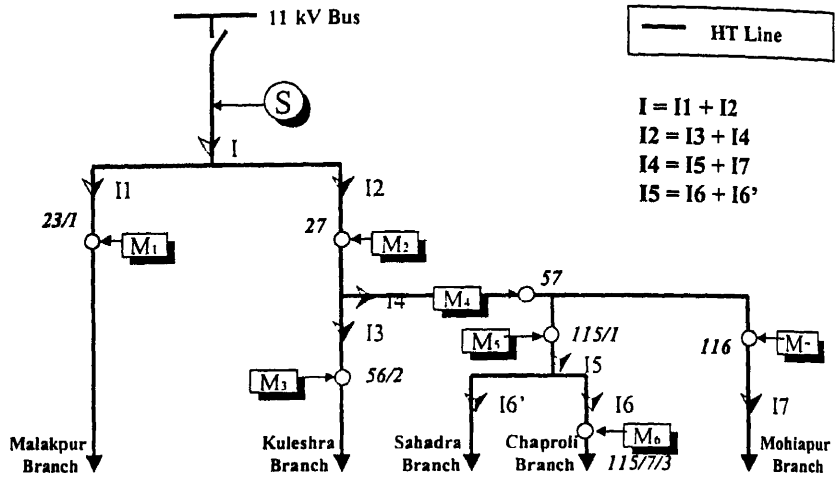
1. Consumption Record
2. Meter & CT Testing
3. Surveillance
4. MRI Tracking

Unauthorised

Unrecorded

Correct / Improve Metering

Nodal Point Metering



$I = I1 + I2$
$I2 = I3 + I4$
$I4 = I5 + I7$
$I5 = I6 + I6'$

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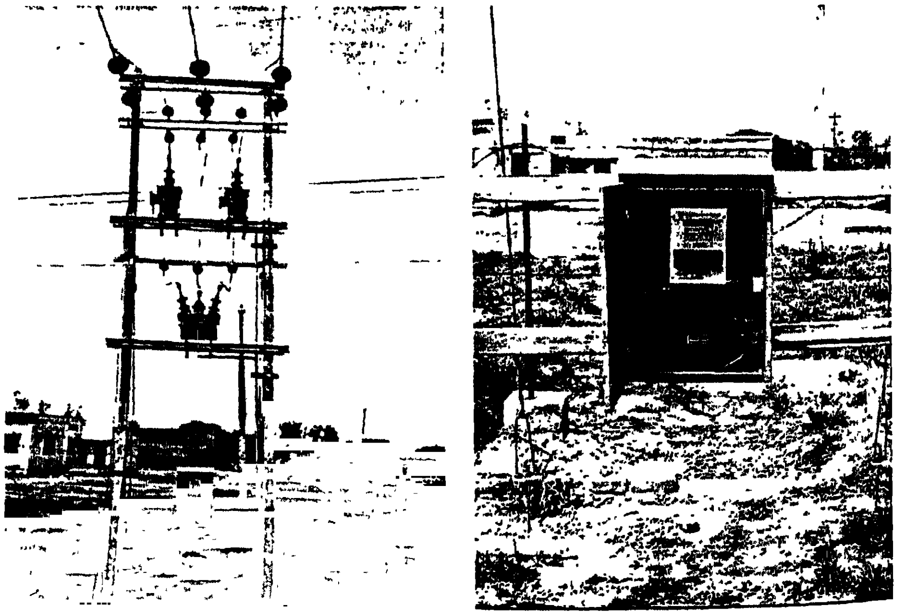

Nodal Metering

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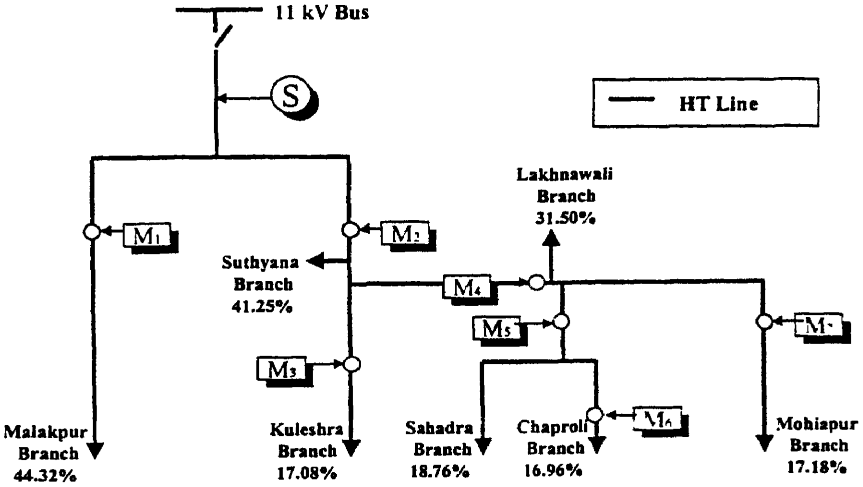
The Loss Tree



Total Loss 20.91%, Technical 9.14%, Commercial 11.77%

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Loss Reduction Strategy

➭ Improvement measures

- ✓ Reconductoring of overhead section – 2 k.m.
- ✓ Implementation of modular scheme for PTW connections – 12 nos.
- ✓ Identification of unauthorised connections – 40 nos.
- ✓ Metered supply with insulated cable – total 120 connections

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Sample Metering of Agricultural Consumption

- Sample size for metering pump sets determined by statistical analysis
- Overall sample size stratified area-wise as per soil conditions/rainfall, cropping pattern, pumpset capacity and water table
- Collection of meter readings at such locations over 12-month period to capture seasonal variation
- Calculation of normative consumption from frequency distribution of meter readings

---

Sample Metering of Agricultural Consumption(Contd..)

- Typical Study

Class	Frequency
0-49	-
50-99	4
100-149	24
150-199	20
200-249	4
250-299	-
300-349	-
350-399	-
400-449	1
450-499	-
500-549	-

$$\text{Mode} = L + \frac{(f_m - f_1)}{(2f_m - f_1 - f_2)} \times I$$

L – lower class boundary

f_m – frequency of the modal class

f_1 – frequency of the class preceding the modal class

f_2 – frequency of the class succeeding the modal class

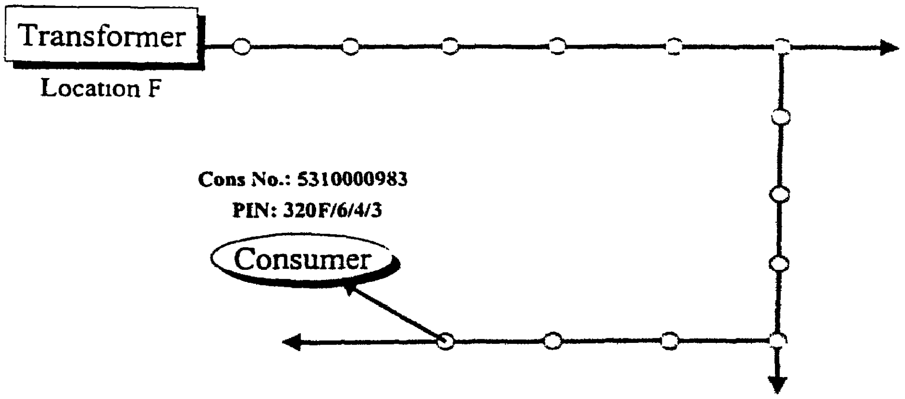
I – common width of the classes

Mode = 142 Units

Building Blocks

- **Addressing Rural Supply**
  - ✓ Identify consumers
  - ✓ Improve HT/LT ratio
  - ✓ Pursue metering, DSM
  - ✓ Innovate & improve

Consumer Identification Scheme



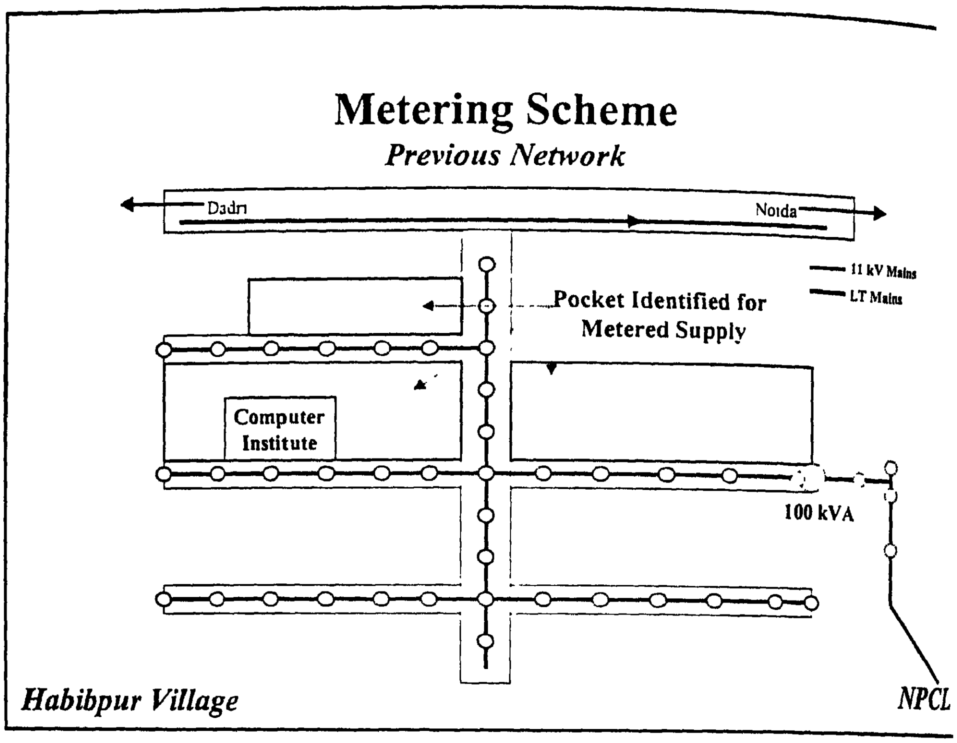
Transformer

Location F

Cons No.: 5310000983

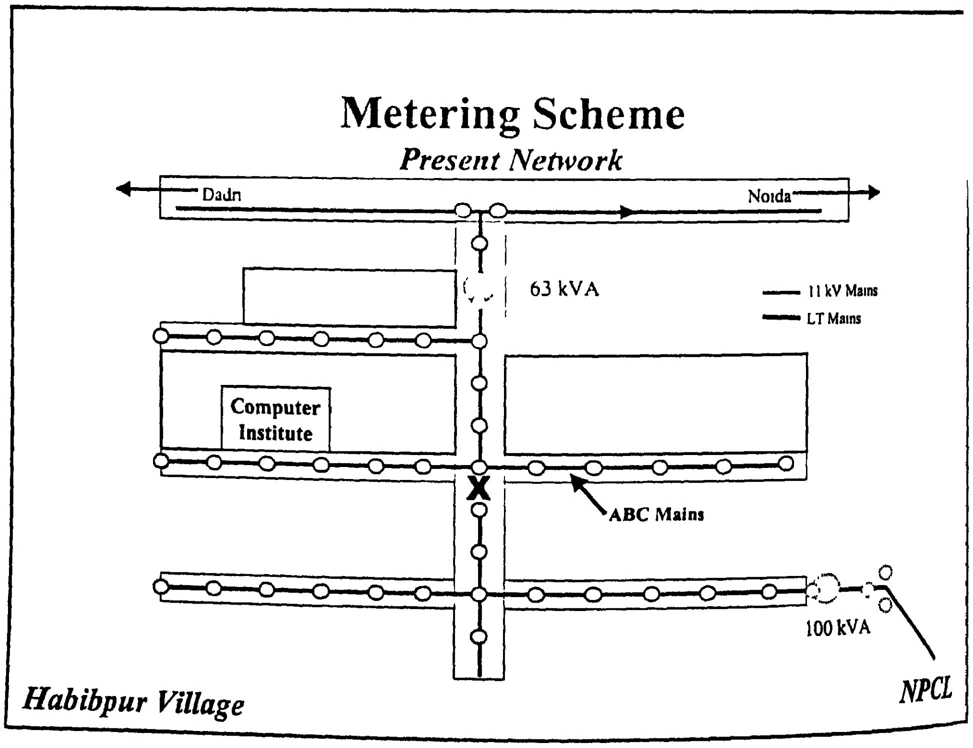
PIN: 320F/6/4/3

Consumer



Metering Scheme

Previous Network



Metering Scheme

Present Network

Metering Scheme – Habibpur Village (Contd..)

Payback Period

✓ **Initial Outlay**

Capital Expenditure	**Rs. 10,00,000**

✓ **Net Cash Flow**

Reduction in Loss	**Rs. 1,00,859**	
Additional Revenue	**Rs. 4,16,328**	
Saving in Cost of Funds	**Rs. 74,939**	**Rs. 5,92,126/year**

Payback Period 21 Months

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Insulated Overhead Mains

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Running Mains

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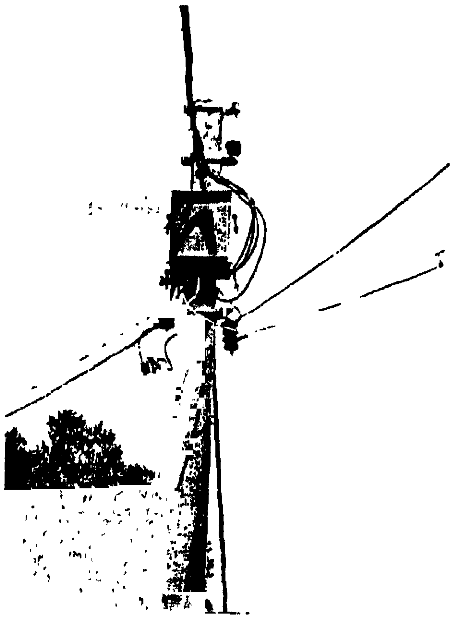

View at Pole

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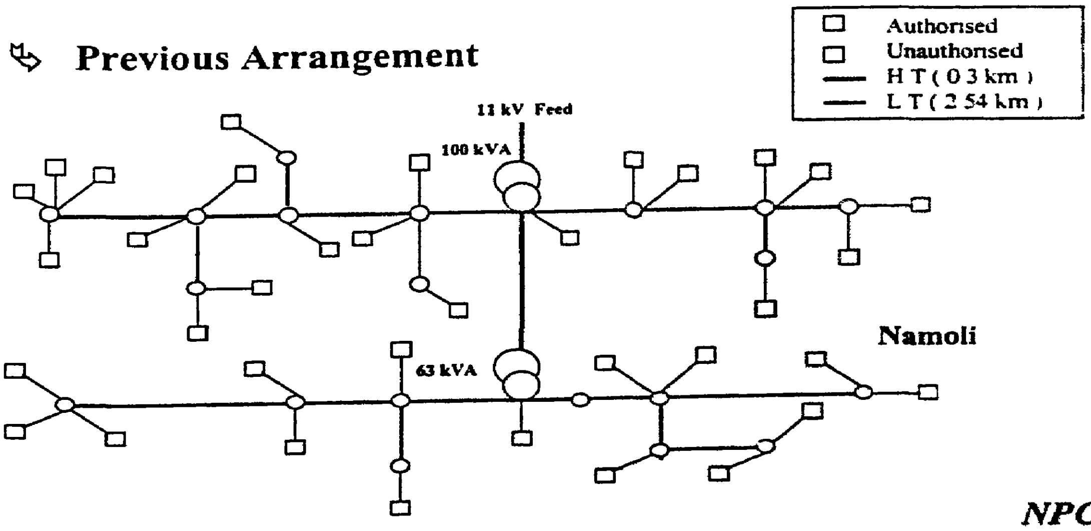
Modular Arrangement

- **Benefits**
  - ✓ Improved HT : LT ratio
  - ✓ Consumer accountability
  - ✓ Ease of revenue realisation
  - ✓ Short payback period

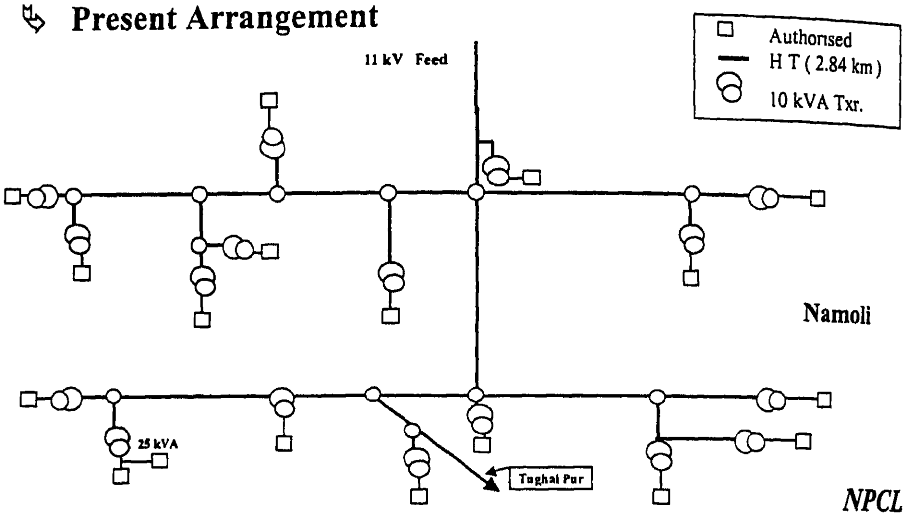
Modular Arrangement (Contd..)

- **Previous Arrangement**



Modular Arrangement (Contd..)

➷ Present Arrangement



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Modular Arrangement (Contd..)

➷ Payback Period

✓ **Initial Outlay**

Capital Expenditure	Rs.7,88,000

✓ **Net Cash Flow**

Reduction in Loss	Rs. 3,37,400	
Additional Revenue	Rs. 16,800	
Saving in Cost of Funds	Rs. 12,000	Rs.3,62,000 / month

Payback Period 25 Months

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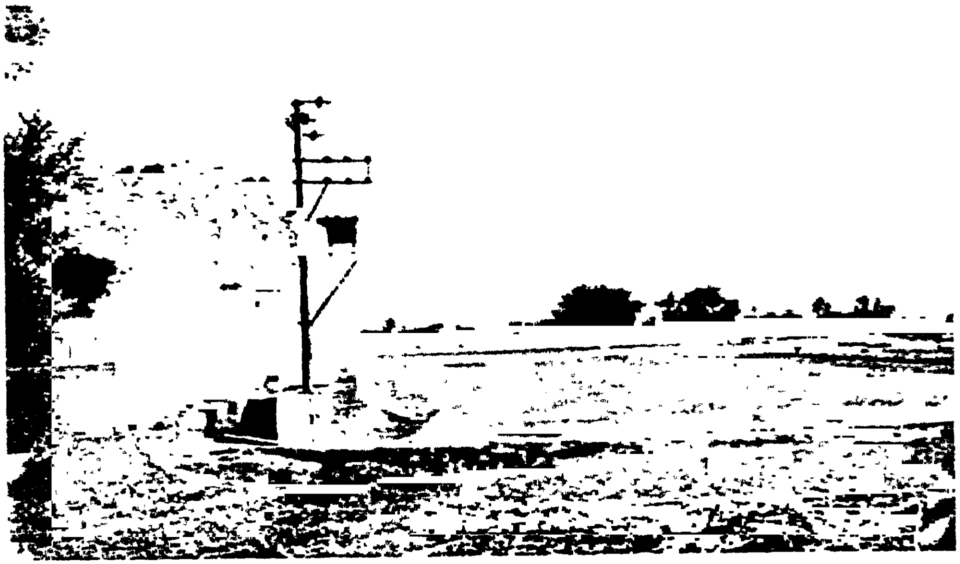

PTW Service

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Demand Side Management

- **Agricultural Pump sets**
  - ✓ Change in design from belt drive to monoblock, rating from 5 to 3 HP
  - ✓ Improvement in P.F. from 0.6 to 0.8, water discharge from 17 to 21 lit/sec
  - ✓ Saving in energy 51% by change in pump design only – strong motive to opt for metered supply
  - ✓ Financing strategies required – farmers reluctant to bear cost of replacement

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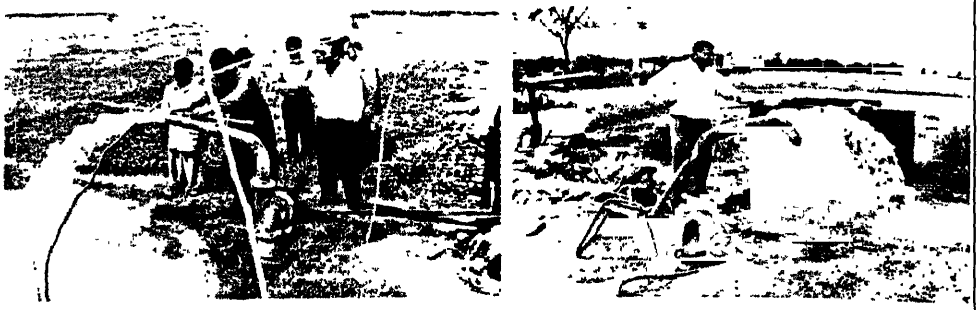

Pump sets

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Metering a Viable Option

- Economy of operation by improving water discharge

Before DSM	After DSM
147 hours	119 hours

- Economy of energy by optimising pump size

Before DSM	After DSM
550 units	268 units

- Economy of electricity cost to consumer

Before DSM	After DSM
Rs. 295 (HP Tariff)	Rs. 188 (Metered Tariff)

Typical Irrigation Area with Watering Requirement of 9000 kl/Month

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Building Blocks

- **People Management**
  - ✓ Build foundation on 'values & beliefs'
  - ✓ Cultivate accountability & performance-bias
  - ✓ Help develop new skill sets & redeploy
- **Technology Focus**
  - ✓ AM/FM/GIS application for network analysis, job planning & control, trouble call management
  - ✓ SCADA system for on-line monitoring and remote control
  - ✓ Integrated IT platform for real time network management

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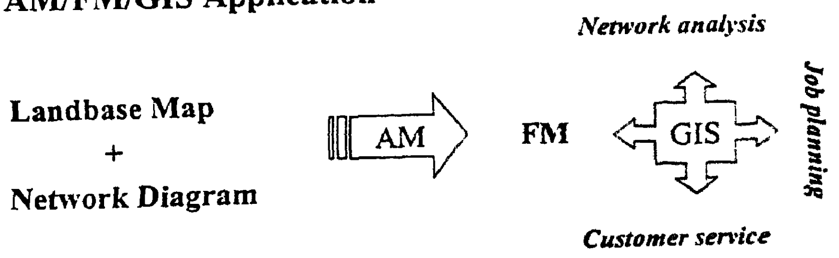
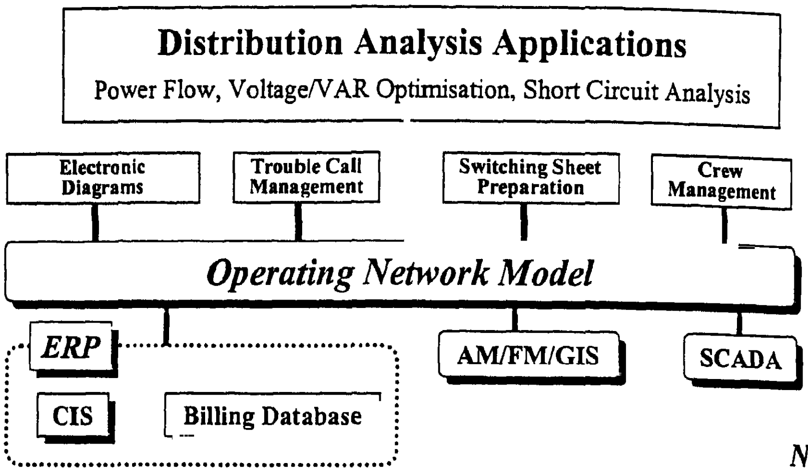
Network Solutions

- **AM/FM/GIS Application**



ERP – GIS – SCADA Integration



Distribution Analysis Applications

Power Flow, Voltage/VAR Optimisation, Short Circuit Analysis

Electronic Diagrams

Trouble Call Management

Switching Sheet Preparation

Crew Management

Operating Network Model

ERP

CIS

Billing Database

AM/FM/GIS

SCADA

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Regulatory Challenges

Readying for Future

- **New Skill Sets**
  - ✓ Demand estimates from econometric analysis
  - ✓ Investments based on IRR/Payback approach
- **New Norms**
  - ✓ Fact based management for performance metrics
  - ✓ Codes of practice defining responsibilities
  - ✓ Good governance for management practices
- **New Mindset**
  - ✓ Cost transparency – Regulator as the watchdog
  - ✓ Public disclosures – Consumer as the partner

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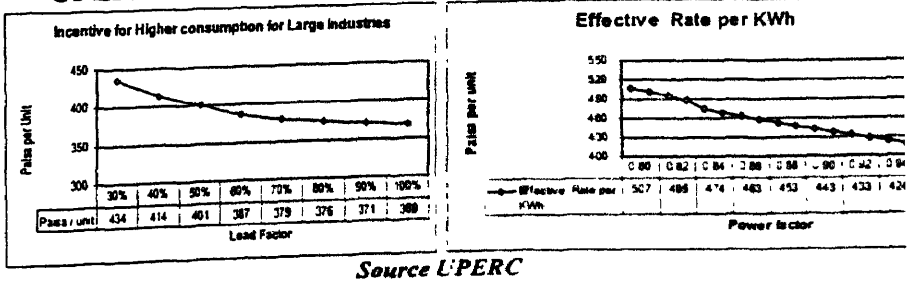
Readying for Future (Contd.)

- **Tariff Imbalances**
  - ✓ UPERC Order a welcome step



Source UPERC

  - ✓ Gross subsidy Rs.370b in 2000-01 (Rs.202b in 1996-97), uncovered subsidy Rs.237b (Rs.58b in 1996-97)
  - ✓ All-round dissatisfaction

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Typical Revenue Model

↳ Multivariate Regression Analysis

- ✓ Identify independent variables influencing consumption — the dependent variable

  Time
  IIP
  Outage
  Tariff

- ✓ Undertake industry-specific analysis — to factor in market and price influences

  Food Products
  Cotton / Textiles
  Basic Chemicals, etc.
  Rubber / Plastic Products
  Machinery & Equipment
  Transport Equipment
  Basic Metals & Alloys
  Other Manufacturing

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Typical Revenue Model (Contd..)

↳ Multivariate Regression Analysis

- ✓ Collate past data to apply in Regression Equation and solve by Method of Least Squares

$$C = aTn + bOn + cIn + dPn + e$$

- ✓ Link projections of IIP with Time Series, Outage with System Improvement Factor (ERDM), Tariff with Electricity Pricing

- ✓ Apply the values of constants to determine the projected consumption for each industry segment

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Typical Revenue Model (Contd..)

↳ Multivariate Regression Analysis (Contd.)

- ✓ Co-relate demand (recorded/billable) with consumption from past data through simple regression ($y = a + bx$)
- ✓ Use same relationship to project future billable demand
- ✓ Aggregate the consumption and demand projections to arrive at revenue assessment

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Service Standards

Licensing

- **Regulator as Licenser**
  - ✓ Regulator has powers to suspend / revoke licence if licence conditions are not met
  - ✓ Licensee has obligation to develop Codes of Practice
    - Distribution Practices – Planning, Operating & Security Standards
    - Performance Standards – Customer Service / Complaint Handling

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Performance Standards

– Electricity Services

Type of Service	*Time Limit for Response / Redressal*
Respond to consumer complaints	**Substantive reply within 10 days**
Restore supplies after fault	
Fuse Calls	**Within 2 hours**
Overhead faults	**Within 6-8 hours**
Underground faults	**Within 16-24 hours**
Transformer faults	**Within 24 hours**
Intimate interruption of supply	**At least 24 hours before**
Reconnect supply	**Same day of payment**

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Performance Standards – Electricity Services (Contd..)

Type of Service	*Time Limit for Response / Redressal*
Investigate voltage / supply complaint	**Visit and reply in 7 days**
Attend meter problems	**Visit or reply in 3 working days** **Remedy within 2 days for industrial connections, 7 days for others**
Attend to billing query	**Substantive reply in 10 days**
Keep Appointments	**As per schedule**

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Performance Standards

– New Connections

Type of Service	*Time Limit for Response / Redressal*
Inspect for new supply and meter	**Within 3 working days**
Estimate charges for connection	**Within 4 days for domestic/commercial** **Within 7 days for LT industrial** **Within 15 days for HT industrial**
Commence supply after payment	**Within 7 days for domestic/commercial** **Within 15 days for LT industrial** **Within 60 days subject to DOES clearance for HT industrial**
Commence billing	**Within 45 days for industrial** **Within 75 days for others**

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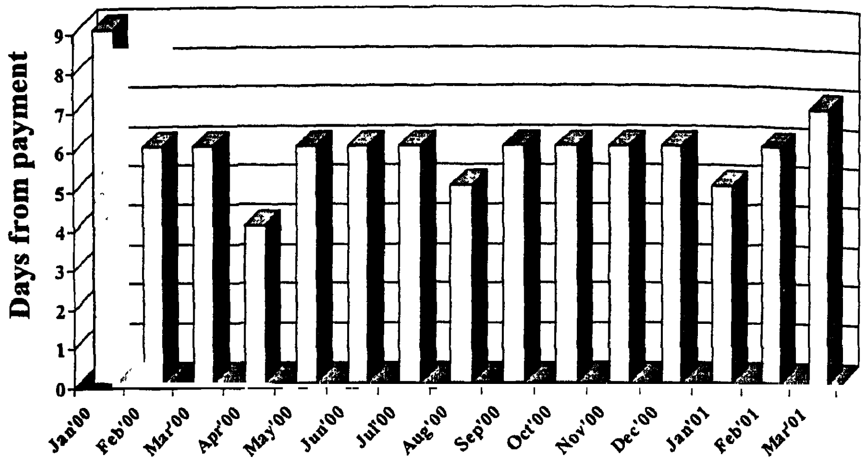
New Service Connection
(Urban Township Area)



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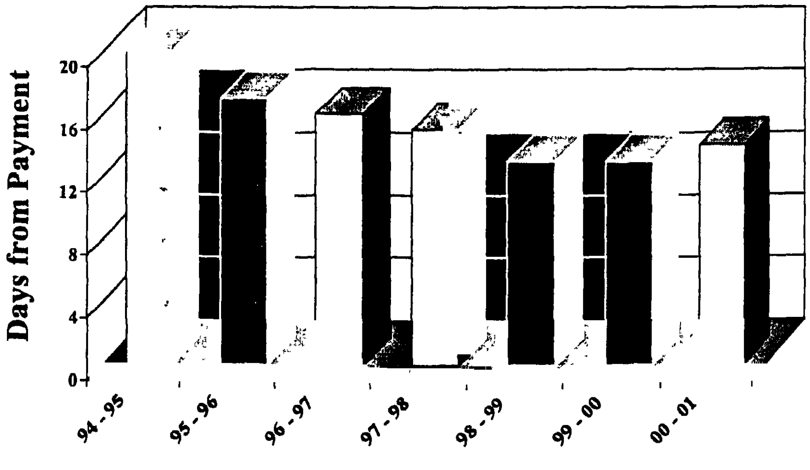
New Service Connection
(LMV – 6 Category)



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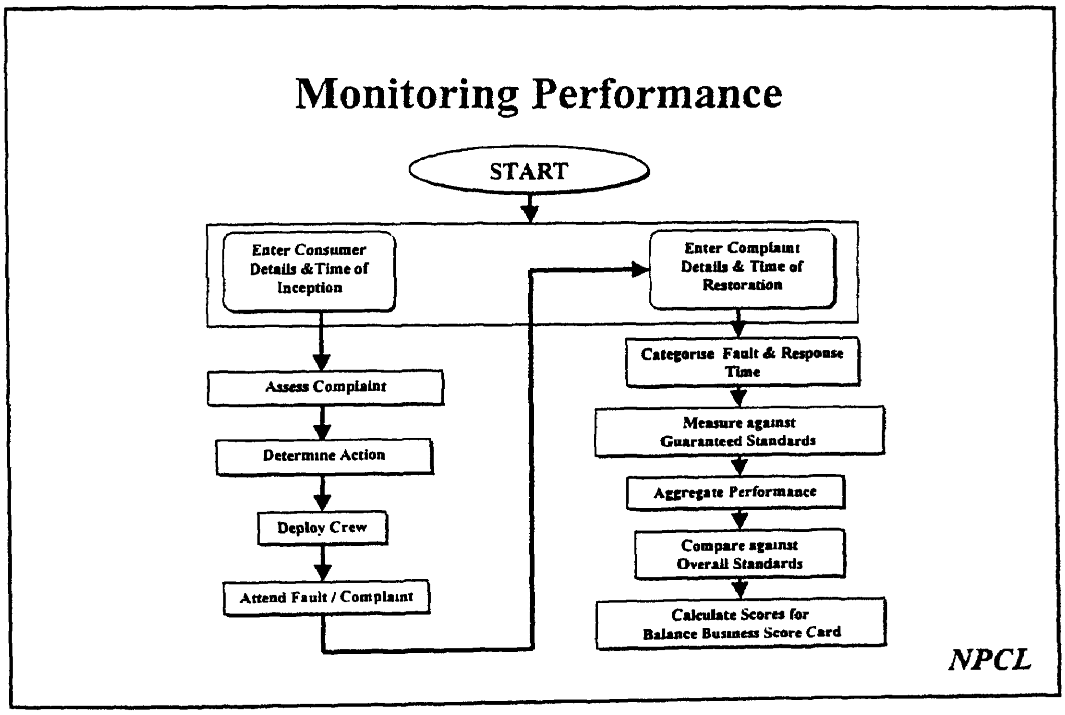

Monitoring Performance

START

Enter Consumer Details &Time of Inception

Assess Complaint

Determine Action

Deploy Crew

Attend Fault / Complaint

Enter Complaint Details & Time of Restoration

Categorise Fault & Response Time

Measure against Guaranteed Standards

Aggregate Performance

Compare against Overall Standards

Calculate Scores for Balance Business Score Card

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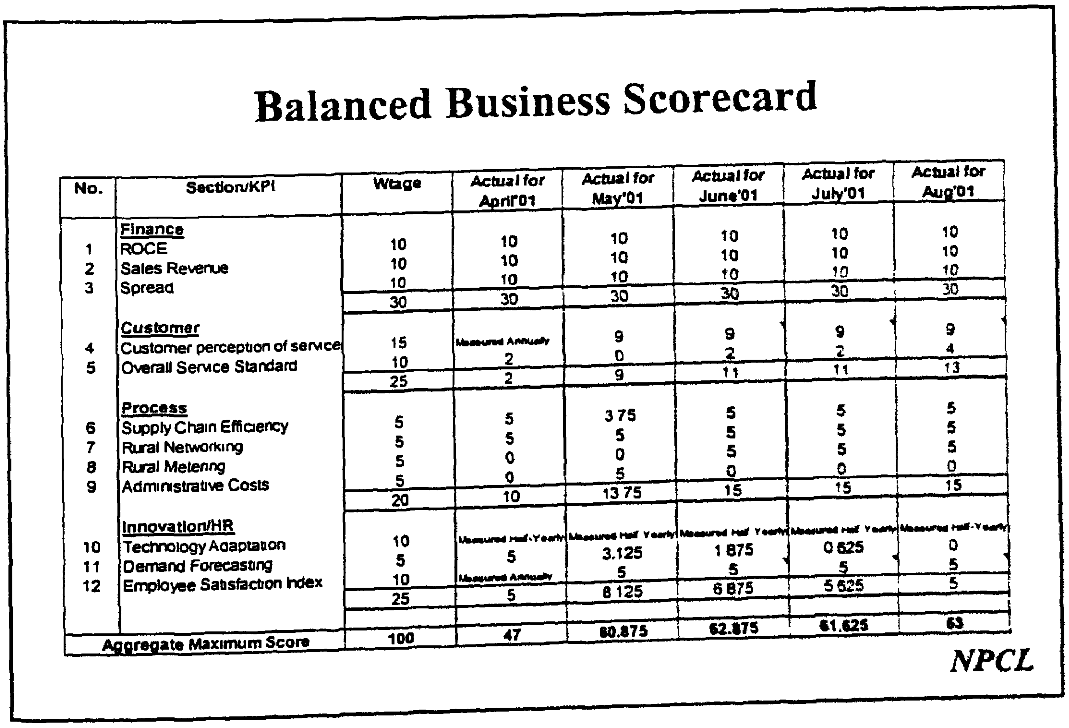

Balanced Business Scorecard

No.	Section/KPI	Wtage	Actual for April'01	Actual for May'01	Actual for June'01	Actual for July'01	Actual for Aug'01
	Finance						
1	ROCE	10	10	10	10	10	10
2	Sales Revenue	10	10	10	10	10	10
3	Spread	10	10	10	10	10	10
		30	30	30	30	30	30
	Customer						
4	Customer perception of service	15	Measured Annually	9	9	9	9
5	Overall Service Standard	10	2	0	2	2	4
		25	2	9	11	11	13
	Process						
6	Supply Chain Efficiency	5	5	3.75	5	5	5
7	Rural Networking	5	5	5	5	5	5
8	Rural Metering	5	0	0	5	5	5
9	Administrative Costs	5	0	5	0	0	0
		20	10	13.75	15	15	15
	Innovation/HR						
10	Technology Adaptation	10	Measured Half-Yearly	Measured Half Yearly	Measured Half Yearly	Measured Half Yearly	Measured Half-Yearly
11	Demand Forecasting	5	5	3.125	1.875	0.625	0
12	Employee Satisfaction Index	10	Measured Annually	5	5	5	5
		25	5	8.125	6.875	5.625	5
Aggregate Maximum Score		100	47	60.875	62.875	61.625	63

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Building Legitimacy

The Change Process

- **Transforming Rural Supply**
  - ✓ Changing mindsets, the 'way of life'
  - ✓ Cementing group behaviour through value proposition
  - ✓ Involving village councils for
    - ➢ meter reading, bill distribution
    - ➢ creating social barriers against electricity misuse
  - ✓ Case for NGO for shaping larger movement
  - ✓ Institutionalising DSM measures for financing strategies

The Change Process (Contd.)

➯ Building Stakeholder Interest

- ✓ Mobilise public support for the reform process — commercially viable utility serves the consumer best
- ✓ Use regulatory mechanism for confidence building — transparent, broad-based process of tariff fixing protects consumers' interests
- ✓ Link user charges to reliable service — consumer will benefit in the long term from efficiency improvements

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The Change Process (Contd.)

➯ Buy In

- ✓ Record consumer voices through independent surveys
- ✓ Assess service levels against consumer expectations
- ✓ Address areas of dissatisfaction as business strategy
- ✓ Document satisfaction index as an annual exercise

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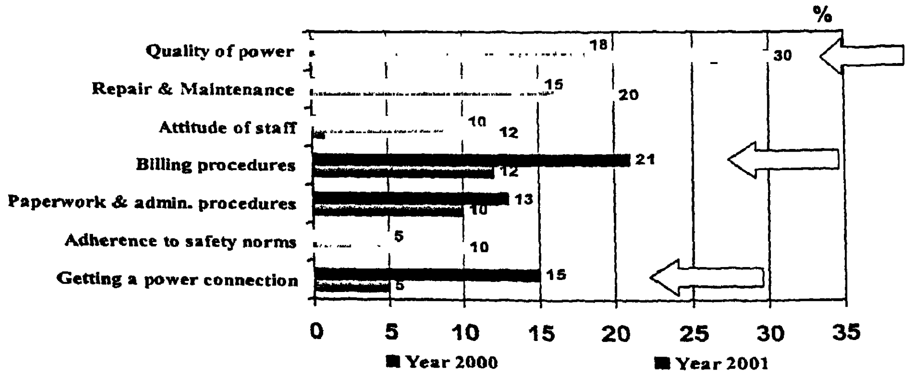
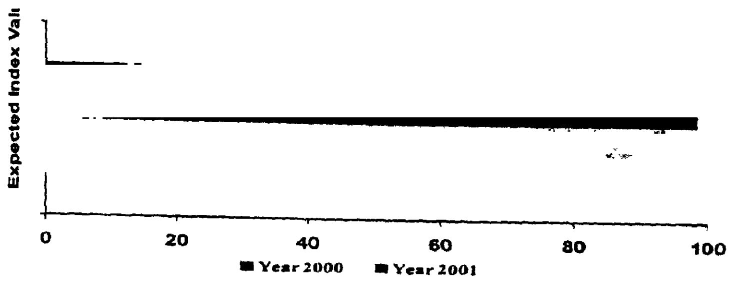
BACKGROUND

- **Research Perspective**
  - ✓Customer satisfaction measured at four levels
    - ✓At an absolute level.
    - ✓Variance from expected levels.
    - ✓Across time i.e. in comparison across years.
    - ✓Across similar utilities.

IMPORTANCE OF END BENEFITS

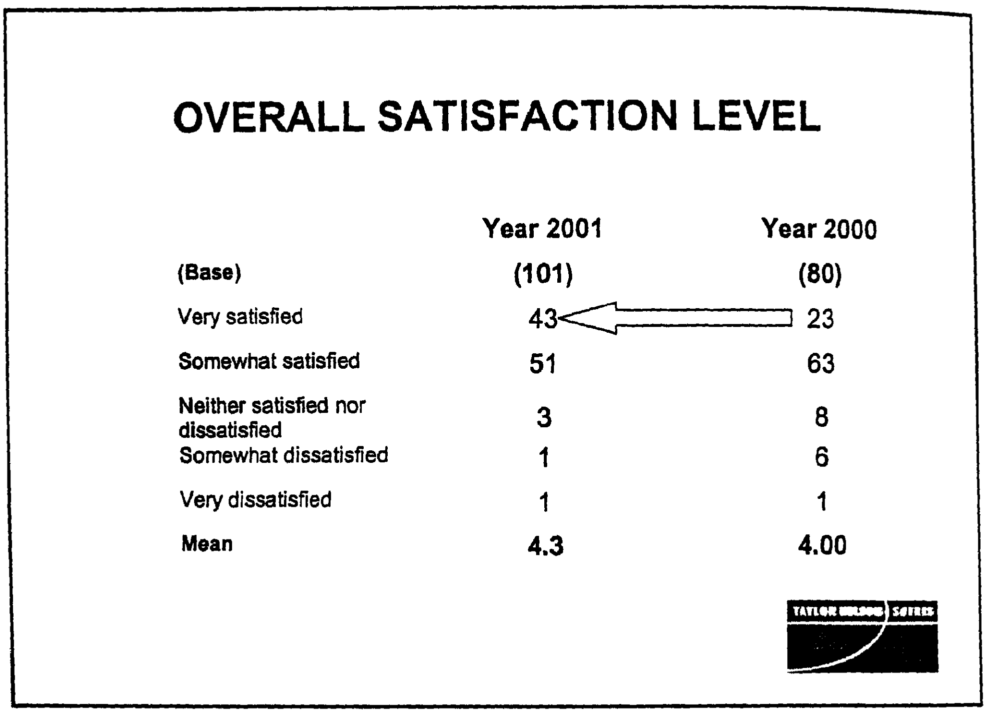


EXPECTATION
2000 v/s 2001



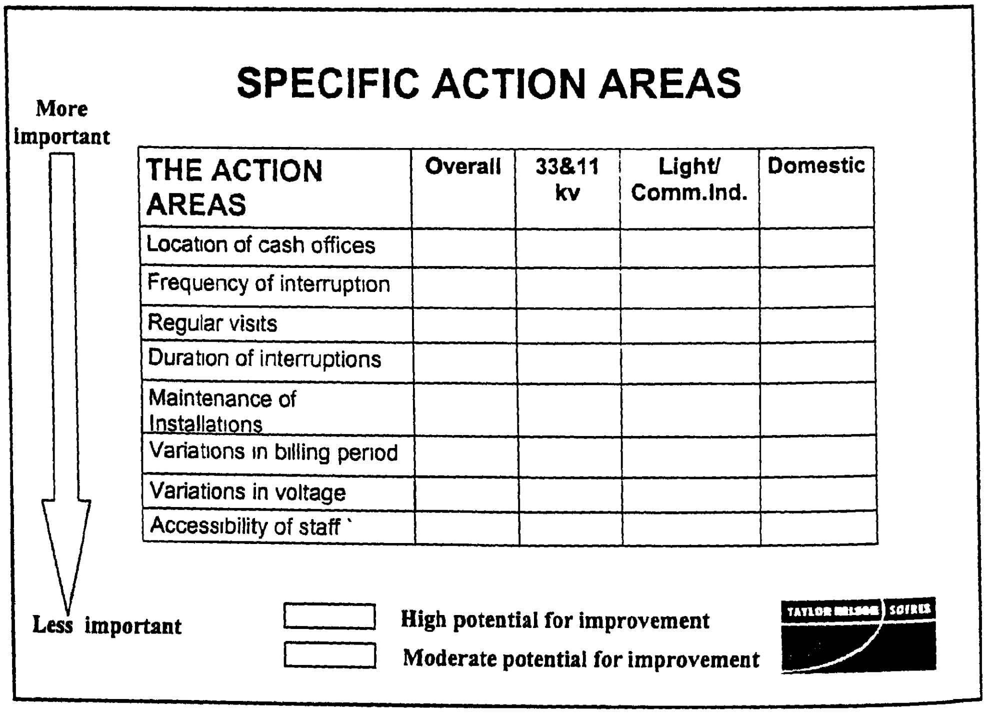
GAP SCORE CARD

	Year 2001	Year 2000
Current performance Index	80	70
Expectation of performance Index	98	93
Gap	**18**	**24**



OVERALL SATISFACTION LEVEL

	Year 2001	Year 2000
(Base)	(101)	(80)
Very satisfied	43	23
Somewhat satisfied	51	63
Neither satisfied nor dissatisfied	3	8
Somewhat dissatisfied	1	6
Very dissatisfied	1	1
Mean	**4.3**	**4.00**



SPECIFIC ACTION AREAS

More important

THE ACTION AREAS	Overall	33&11 kv	Light/ Comm.Ind.	Domestic
Location of cash offices				
Frequency of interruption				
Regular visits				
Duration of interruptions				
Maintenance of Installations				
Variations in billing period				
Variations in voltage				
Accessibility of staff `				

Less important

☐ **High potential for improvement**

☐ **Moderate potential for improvement**

Policy Imperatives

Macro-economic Context

- **Sector Issues**
  - ✓ Distribution business not having infrastructure status u/s 10(23G) of I.T. Act
  - ✓ Distribution business subject to MAT – unlike generation or generation & distribution business
  - ✓ Open access regime for Distributor to exercise least cost option of power purchase – third party access, wheeling mechanisms to be addressed

Macro-economic Context (contd.)

Sector Issues (Contd.)

- ✓ Economic legality, contract enforceability pre-conditions to investor confidence – guarantee of off-take in quality & quantity
- ✓ Labour reforms critical – for outsourcing options, redeployment & right-sizing
- ✓ Electricity Courts the crying need – to deal with electricity offences & defaulters and avoid cumbersome legal proceedings

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Thank You

Renewables

Electricity Sector Reform in Developing Countries: Implications for Renewable Energy

By Dr. Keith Kozloff 1

Electricity power reform can stimulate renewable energy use in developing countries. But the moment of opportunity will soon pass. If developing nations adopt rules that lock in conventional technologies, they will lose a unique occasion to develop a clean, economically efficient power sector that serves more people at an affordable price.

This paper explores how different reforms either promote or inhibit the growth of renewables in developing countries. The first section considers the advantages of renewable energy for these nations and its deployment thus far. Part II provides a taxonomy of current reforms. Because the effects of reforms on renewable bulk power and renewable distributed applications differ, subsequent sections treat these two markets separately. Part V summarizes major conclusions and offers recommendations for using the reform process to promote greater use of renewables.

PART I. Renewable Energy Markets in Developing Countries

Renewable energy resources -- sunlight, wind, running water, biomass, and geothermal heat -- are widely distributed throughout the developing world. They are starting to be exploited through a range of technologies that convert natural energy flows to electricity. Their declining costs and commercial maturation mean that technologies that rely on renewable resources can now be used in a variety of situations.

Advantages of Renewable Energy

Renewable resources are indigenous, do not require fuel purchases, and can be used locally for power generation. So they are particularly advantageous for off-grid applications. In fact, the future of renewables in the developing world may be determined by the extent to which they are used to serve rural populations. At present, roughly 2 billion people in the world do not receive electricity. Other households are nominally served, but service is so unreliable that they choose to invest in their own sources of power. In the absence of reliable grid power, residents become "self-generators" -- they use diesel generators, kerosene lamps, lead acid batteries charged by diesel generators, candles, and diesel pumps. Many of these sources emit pollutants with adverse environmental and health effects.

In addition to their other advantages, renewable resources could play a significant role in limiting the environmental effects of energy use. Many developing countries, including China and India, are burning increasing quantities of coal to generate power -- with both local health and global climate effects. Improving the environmental performance of the power sector requires changing the generation mix, installing pollution controls, and limiting power demand by improving energy efficiency.

As a result of rapidly growing electricity demand, carbon emissions in the developing world are projected to outpace those in countries that belong to the Organisation for Economic Co-operation and Development (OECD).2 (See Figure 1 on Page 2). According to the World Bank, improving the efficiency of electricity generation, distribution, and use will not be enough to keep greenhouse gas (GHG) emissions from increasing over the next 25 years; doing so will require moving away from dependence on fossil fuels.3 Switching to low- and no-carbon technologies, including renewables, for new electricity generation is the only way for developing countries to cap both their GHG emissions and local pollutants.

At the same time that interest in renewables is growing, developing countries are reforming the way electricity services are provided. (See Box 1.) On the one hand, reforms could offer renewables the opportunity to compete fully and fairly for market share in some countries for the first time. On the other hand, they could further entrench energy technologies that pose local and global environmental threats.

The stakes regarding the impact of reforms on renewables are high. Total projected growth in electricity consumption between 1993 and 2015 in non-OECD countries exceeds that of industrial countries. (See Figure 2.) Asia will contribute the largest increase. (See Figure 3 on Page 5.) Due to high electricity demand growth rates -- in some countries, in the double digits -- new investments in the power sector made in developing countries over the next 20 years will be as large as cumulative investments to date. Countries that have initiated reforms already constitute 78% of generating capacity in non-OECD countries.

Renewable Energy Deployment to Date

Until recently, the deployment of renewable energy technologies in developing countries occurred primarily through direct government investments or international donor programs in which renewables did not compete in open markets. Where renewable pilot projects have been implemented by publicly owned and managed utilities, the decision was often made in order to meet planning, political, or technological objectives.

Today, however, renewables are increasingly deployed commercially in competitive markets. And public support is more oriented toward creating a market environment in which renewables can compete fairly for market share.

Renewable energy technologies compete with nonrenewable technologies to penetrate markets for "bulk" (large-scale) and "distribution" power generation. (The latter refers to small-scale generation to support a grid, to power village mini-grids, or to serve individual households.) Consumers can also use renewables instead of electricity to meet demand-side needs (such as daylighting, water heating, and space conditioning). (See Table 1 on Page 6.)

The successful penetration of renewable energy into bulk markets depends on several factors -- the quality of locally available resources, technological developments affecting the relative cost competitiveness of renewable versus nonrenewable options, and the structure and operation of such markets. Large hydropower, geothermal, and biomass cogeneration (combined heat and power) have already made significant contributions to meeting bulk power needs in several developing countries. For example, India has become a leading wind power producer.

Renewables have also made inroads in distributed power markets, primarily for rural electrification. Local dealers are marketing solar home systems and related services, for instance, in the Dominican Republic, Kenya, India, Sri Lanka, and Zimbabwe. A World Bank loan for solar home systems in Indonesia is based on a competitive market of individual small entrepreneurs.4 In such markets, renewables are competing with energy sources based on fossil fuels that are transported long distances or with the generation, transmission, and distribution costs of grid extension.

The future market penetration of renewables in developing countries depends on which model these countries emphasize for power sector expansion. The central station model (in which power lines emanate from a large generating station) has dominated in the United States and other industrial countries. However, more recently an alternative, pro-renewables model has been evolving. This "distributed utility" model places less emphasis on central generation and more on modular generation units that are strategically located close to where power is actually needed -- which is especially desirable in countries with large unconnected rural populations. (See Box 2.)

Because OECD countries export both their technologies and their infrastructure models, it is too soon to say whether the distributed model will take hold in developing countries.

PART II. Major Types of Power Sector Reform

Typically, governments implement a package of reforms in the power sector. By and large, however, the decisions regarding specific reforms can be separated and occur at different points in time. By understanding the various implications for technology choice, policymakers in developing countries can make informed decisions about what types of reforms to adopt and hov to implement them.

Characteristics of "Pre-Reform" Power Sectors

In most developing countries, the power sector has been publicly owned, viewed as a public service, and often dominated by a central planning philosophy. Universal electrification is frequently a national policy objective, as is the provision of electricity services to low-income customers at subsidized rates. In some countries, both upstream sectors (fuel extraction and transport) and downstream sectors (major industries) are also under government control and ownership. Rural electrification has generally been the responsibility of the government utility, although rural electric co-operatives have also been active, particularly in Latin America. (See Box 3.)

Because of poor cost recovery, managerial inefficiency, and inability to attract sufficient capital, the gaps between electricity supply and demand are widening in many developing countries. Sel. generation (using diesel generators, for example, or kerosene lamps) constitutes an average of 13% of total power generation in the 75 developing countries with available data, and represents over 25% in 12 countries, mainly in Africa.5

Using distributed generation to reduce distribution system investments (such as substations) has been extremely rare in developing countries. Since evaluating distributed applications requires detailed time- and location-specific cost data, most developing-country utilities are not able to complete the needed investment analyses.

In the pre-reform world, renewable energy technologies, such as solar water heaters, have playec a modest role in reducing power demand. Utilities have invested in demand-side management (DSM) in several countries, including Brazil, Indonesia, and Thailand. Elsewhere, government agencies have sponsored such programs. Under state ownership and management of utilities, DSM activities will continue where they have been started, but often at levels constrained by weak end-user price signals and by utility revenue shortfalls that are covered by transfers from the national treasury.

Although these characteristics tend to distinguish pre-reform utilities in developing countries from their OECD counterparts, the power sectors in these countries are by no means homogeneous. For example, fossil or hydro capacity may dominate the current generation mix. Some power sectors are too small to gain much from competition; others would benefit from it. Electricity demand per capita and per unit of national income also varies widely.

Changes in Power Sector Ownership and Operation

To address the critical challenges facing their power sectors, many developing countries are now reforming the way that electricity services are provided. They are opening power generation to private investment, further privatizing transmission and distribution, and even restructuring the sector to introduce competition and independent regulation. Governments are reforming the electricity sector to stimulate private investment and thus free up large amounts of public capital for other uses, to promote managerial accountability and better customer service, and to reduce government deficits and international debt.6

Developing countries tend to emulate successful electricity sector models pioneered in a single country. In the 1940s and 1950s, developing countries generally modeled their power sectors on their main economic partners among industrial countries (France, the United Kingdom, or the United States). In the 1980s and 1990s, reforms adopted by Chile and Argentina have been sweeping Latin America (Guatemala, Bolivia, Colombia, and Peru). Also in the 1990s, privately developed power plants have been spreading across Asia, Central America, and the Caribbean, although with less competition than in the United States. Francophone Africa has been experimenting with privatizing utility management, based on French models.7

Commercialization involves introducing commercial objectives into the management and operation of a state-owned enterprise. Subsidies are often removed, including state guarantees for borrowing, and the enterprises become subject to the same tax laws, prices, and accounting rules as other companies in the private sector. To make the company more attractive to private investors, the state-owned enterprise may assume past debts, reduce staff, and provide new operating capital. As part of commercialization, cost accounting is separated for generation, transmission, and distribution services.

An important part of broader managerial reforms is recovering the actual costs of electricity service. (This is often required as a condition for receiving concessionary loans from multilateral development banks.) Cost recovery is improved by adjusting rates to better reflect the costs of serving individual customer classes, by upgrading revenue collection with more effective metering and billing practices, and by reducing energy theft. A few countries have begun to charge customers different rates according to the time of day when power is demanded.

Most countries view commercialization as an intermediate step toward privatization and other reforms, although some have commercialized their power sectors but may never privatize them. Countries in this category include Cote d'Ivoire, Ghana, Malaysia, Senegal, Singapore, and Thailand.

Privatization transfers existing power sector assets to private ownership and allows private development of some or all new power sector infrastructure. While privatization of public enterprises in various economic sectors has been a widespread phenomenon among both OECD and non-OECD countries over the past decade, the electric power sector is typically one of the last enterprises to be affected because its functions are considered by politicians to be vital to the state.

The traditional method of assigning new projects for private-sector development is for the utility to draw up expansion plans and assign specific projects for private financing. Another approach is to specify capacity requirements and let the private sector identify least-cost sources. Several models exist for private participation in power generation -- for example, Build-Own-Operate (BOO), Build-Own-Operate-Transfer (BOOT), Build-Maintain-Transfer (BMT), and Build-Lease-Transfer (BLT). Developing or emerging economies that allow private power include Argentina, Bolivia, Brazil, Chile, China, Colombia, Costa Rica, Cote d'Ivoire, the Dominican Republic, Guatemala, Guinea-Bissau, Honduras, India, Indonesia, Jamaica, Kenya, Laos, Malaysia, Mauritius, Mexico, Morocco, Nepal, Pakistan, Panama, Peru, Philippines, Poland, Russia, South Africa, Tanzania, Thailand, Turkey, Ukraine, and Viet Nam.

Power purchase agreements (PPAs) are a key component of schemes in which private developers retain ownership of the generation facility (BOO). A PPA's single most important provision is the price at which the utility agrees to buy power from the developer.8

The range of ownership reforms is bounded by full private responsibility for operation of existing assets and new investment, through either long-term concession or change in ownership. Major sales of power sector assets have occurred in Latin America, and partial sales have occurred in Indonesia, the Philippines, and India.

Privatization is commonly associated with politically independent regulation of those power sector components that remain in monopoly control. Full privatization means that the private-sector operator takes its revenue from final customers. Regulation is supposed to ensure that the tariffs charged allow the utility a fair return on its investment.

Although tariffs may be reformed as part of commercialization, the utility's incentives to recover costs become even stronger when a private owner takes over. Allocating ownership and management to the private sector and giving regulatory functions to a public agency that is at least partially independent of political pressure increases the prospects for basing tariffs on actual costs of service. Tariff subsidies are common in developing countries, but reform does not necessarily mean price increases. Depending on customer class, cost-based tariffs could go up or down.

Restructuring alters the existing organization of the electric industry. In the extreme, vertically integrated utilities (providing generation, transmission, distribution, and retailing services) are unbundled into legally and functionally distinct companies. Chile, England, and Wales pioneered unbundling models in the 1980s. Since then, developing countries or states in which generation, transmission, and distribution assets have been or are being separated include Argentina, Bolivia, El Salvador, the Indian state of Orissa, Nicaragua, Pakistan, and the Philippines. Unbundling is also popular in Eastern Europe.

Variations among countries exist within the overall framework of unbundling. In some, the distribution services have also been divided according to geographic franchises. And in some countries, independent generators sell to a single power procurement business. Such single-buyer models are appropriate for smaller systems, where the potential gains from competition are too small to offset transactions costs.9 Also, some countries have separated electricity distribution from retail services, while others have kept them within the same company.

While the "wires" portion of the electricity sector (transmission and distribution services) is still considered a natural monopoly, competition may be introduced into the system for selling power to the grid (wholesale competition) and providing electricity to end-use customers (retail competition). Wholesale competition may take the form of independent power producers (IPPs) bidding for long-term contracts with power purchasers. Although many styles of bidding exist, commonly the utility solicits bids from project sponsors and awards the lowest-cost supplier, regardless of the type of generation. The selection emphasizes lowest fixed costs, and the winning bidder receives payment sufficient to cover fixed investments and operating costs. Purchasers tend to award contracts on the basis of capacity and energy costs in the first few years of a project's 30-year life span.

As an alternative to awarding long-term contracts, some countries (such as Chile and Argentina) are creating spot or short-term markets for wholesale power. Under this model, multiple generators bid to be dispatched by an "independent system operator" (ISO). The ISO purchaser relies on competition to ensure that bids are kept low. (If individual generators constitute too large a share of the market, they can manipulate output or availability to increase profits.) Generation projects that depend on spot markets for most of their revenues are called "merchant plants." (See Box 4.)

In addition to wholesale competition, a few places (California, England, Norway, and Wales) are experimenting with retail competition for some or all customer classes. Retail competition is most feasible in areas with significant numbers of industrial and large commercial customers, who are typically more attractive targets for competing firms than residential customers. Consequently, governments can open competition for large customers and then phase in smaller customers.

Retail competition can be introduced through different methods. In one, multiple power generators have direct access to the transmission and distribution networks (for a charge), allowing them to compete to supply final customers regardless of their location or who owns the wires. In another, independent retail service providers (which do not own any generation facilities) buy power from generators, contract for use of transmission and distribution facilities, and sell the power to final customers. Where distribution and retail functions remain within the same entity, the service provider buys from wholesale power producers and contracts for transmission access.

PART III. How Reforms Affect Deployment of Renewables in Distributed Power Markets

Distributed applications constitute the largest near-term market for several renewable energy technologies. The reforms under way in numerous developing countries affect the extent to which the distributed resource model, particularly regarding renewables, is used when expanding the sector's infrastructure.

Commercialization

Commercialization generally favors renewables, at least compared with a situation in which there is no reform. When utilities commercialize, they are forced to attend to cost recovery. This means that they may reduce subsidies to rural customers, sending more accurate price signals. Better management is likely to mean better information on cost of service and more attention to the environmental implications of investment choices. A commercialized utility is more likely to identify the least costly manner of extending service to rural areas.

Commercializing a public utility may improve its incentives to implement DSM and grid support applications of renewables. To the extent that a commercialized utility has an incentive to reduce sales to where the cost of supplying the next kilowatt-hour is greater than the revenue received, it should be willing to pay up to the difference (the cost subsidy) not to have to supply that kilowatt-hour. For example, a utility could invest in photovoltaic-powered water pumps in lieu of extending the grid to farmers who would receive heavily subsidized power. Grid power could be reserved for urban customers who pay the full cost of service. In a country with unmet demand for power, this policy would not necessarily result in "lost revenues."

Privatization

Privatization has mixed effects on distributed applications of renewables. It strengthens the managerial improvements and cost recovery changes begun under commercialization. At the same time, when ownership is transferred to the private sector, the cost of capital used in making investment decisions is likely to increase. As a result, demand-side investments yield a lower rate of return than they would under public ownership because the investment is made right away while the benefits, accruing over a period of years, are discounted.10 For this reason, fewer DSM measures are attractive to a private utility than to a public one.

Second, privatization is likely to dampen interest in serving rural markets, where renewables have a comparative advantage. In some countries, the government regulator grants the new private owner a long-term concession for the right to distribute electricity to a defined geographic area that includes both urban and rural customers. Unless required by regulation, the privatized utility is reluctant to extend service where doing so does not meet its profitability criteria. The ability to cross-subsidize rural customers is limited. Shareholders may require higher rates of return to justify investments in rural markets, which are viewed as being relatively risky. In addition, the utility may or may not have the authority, interest, or expertise to pursue other means of providing electricity services to rural areas. To address these issues, the Government of Argentin is implementing a "rural concessions program" (see Box 5 on Page 11), and Brazil is considering a similar initiative.

Third, public utilities have often pursued other social objectives in addition to universal electrification that may have involved deployment of renewables, such as economic developmen and technology commercialization. When a utility is privatized, its pursuit of social objectives in response to national policy or political mandates wanes. The responsibility for implementing suc objectives transfers to regulators, who seek to balance these goals with the utility's economic well-being.

Fourth, the form of regulation that accompanies privatized retail services affects the incentives fc end-use customers to invest in on-site renewables. Under some tariff structures, customers could see fully itemized rates based on area- and time-specific energy, transmission system capacity, and distribution capacity costs. Depending on the previous structure, such rates could improve ratepayers' economic incentives for managing their demand and reducing consumption. Key factors include how costly it is to install meters that charge according to time-of-use, whether location-specific costs can be differentiated, whether hook-up fees reflect the customer's load, an whether meters are allowed to "run backwards" to credit on-site generation. Regulators might als adopt policies to improve incentives for electricity suppliers to make demand-side investments that reduce system-wide costs.[11]

Restructuring

The implications of separating a utility into independent firms that individually provide generation, transmission, distribution, and retail services for distributed applications of renewables depend on how the allocation of costs changes. Before unbundling, a utility can calculate the value of distributed generation by adding up the costs associated with central statio generation, transmission, and distribution that are avoided. After unbundling, the entity most likely to be considering distributed generation investments (the distribution company) may not b able to fully identify, value, and capture upstream generation and transmission costs that would be avoided by such investments. At best, the way that upstream costs are passed through in an unbundled power sector would not diminish the cost-effectiveness of distributed generation to a distribution company. At worst, unbundling causes the set of attractive distributed generation investments to shrink. Still, distribution companies might find some such investments to be cost-effective in locations where:

- the marginal costs of service are particularly high due to network constraints;
- service must be extended to customers with low loads who are far from the grid; and
- sharp local peak demand results in inefficient use of distribution assets.

Competition

Competition affects the attractiveness of investments in distributed renewables in several ways. First, a thriving competitive wholesale market should drive down generation expenses, thus reducing the costs that can be avoided by distributed renewable installations. Spot markets, for example, often operate on the basis of competing generators' short-term operating costs. Compared with long-term power purchase agreements based on full costs incurred over a project's life, spot generation markets weaken the incentive to invest in distributed renewables whose costs must be recovered over a period of several years.

Second, competition among electricity suppliers for retail customers creates an incentive to minimize capital investments that would put upward pressure on rates in the near term, even if they would hold down rates in the long term. Over time, the focus of retail competition may shift from low cost to customer value. If so, retail suppliers may offer packages incorporating distributed renewables, including demand-side applications, to differentiate themselves from competitors.

Third, competition at the wholesale and retail levels is likely to make retail rates more variable and less predictable. End-users investing in demand-reducing measures face the risk that the dollar savings over the life of the measure may be less than expected. This risk is exacerbated when future electricity costs are less certain.

PART IV. How Reforms Affect Deployment of Renewables in Bulk Power Markets

To date, few publicly owned and managed utilities have constructed bulk renewable generation facilities other than large hydro. They have not had strong capabilities for adopting emerging technologies and have tended to use more familiar and conventional generation equipment.

Commercialization

By itself, commercializing public utilities has little effect on renewables in bulk power markets. Still, the ability to adopt new technologies may be improved. Renewables may be considered more seriously to the extent that improved management, cost accounting, and cost recovery increase the utility's interest in choosing the least-cost approach to expanding service on a life-cycle basis.

Privatization

Similarly, privatization is unlikely by itself to increase the market share of renewables. Technology preferences for investments in new generation result partly from differences in project financing available to public utilities, private utilities, and independent power developers. When new generation is privatized and unbundled, independent power producers must generally finance projects on the basis of the expected returns from the specific project and the need to recover investment over the loan repayment period. In contrast, public utilities, backed by sovereign guarantees, often face lower costs of capital. Because even well-capitalized private developers do not have the credit capacity to underwrite the debt on a portfolio of projects whose total capital costs may be hundreds of millions of dollars, obtaining third-party debt is essential. Consequently, independent power developers face a higher cost of capital and a shorter repayment period than vertically integrated utilities. They must recover their investment over the period of their loan repayment. All things being equal, the cost of energy from a capital-intensive renewable project to either a private utility or an independent power producer is higher than to a public utility. (See, for example, Box 6.)

Because of these financial considerations, private developers prefer generation options that have relatively low capital costs per megawatt, a short construction time in order to yield revenue quickly, high efficiency, and the ability to be operated most of the time. Based on recent trends, private developers appear to favor natural gas generation (sometimes even where liquefied natural gas must be imported) due to its cost structure and short construction time. Generation options that are not favored are coal, nuclear, hydro, and other renewables. In developing countries where public power systems have relied heavily on hydro, for example, the transition to private financing has resulted in increased use of thermal generation at the expense of hydro. Hydropower is unattractive to independent power developers because of its capital intensity and relatively long lead time (for large projects).12 In Latin America, natural gas has often displaced hydro for new generation. In Asian countries where natural gas is not available for power generation, coal often displaces hydro for new capacity.

Power purchase agreements can also affect financing for renewables, depending on the extent to which provisions in these agreements are geared to the characteristics of renewable generation options. Since most independent power projects have been thermal to date, the terms of standard PPAs are often geared to such projects. Payment schedules and other terms in PPAs may create incentives for independent power producers to choose relatively low capital-cost-per-megawatt generation technologies over options with comparable life-cycle costs but higher capital costs. PPAs often guarantee fixed price payments to developers over a limited period of time. Adequate payment schedules are particularly critical for capital-intensive power generation options, a characteristic of geothermal, wind, hydro, solar, and thermal options. Independent power developers must attract private debt financing on the strength of PPAs. They must often recover their capital investments over the fixed price contract period (generally less than the facility's life span). This is harder to do for developers of capital-intensive generation options, putting them at a competitive disadvantage relative to developers of fuel-cost-intensive options.

Renewables face other barriers in obtaining long-term power contracts. Transaction costs incurred to participate in the bidding process may favor certain technologies. Per megawatt, the costs of preparing a bid for a thermal project are less than for a renewable project. They can be readily determined and are not particularly site-specific, allowing bids to be prepared more quickly and cheaply. Developers of small-scale renewable power sources may find the transaction costs of negotiating PPAs prohibitive.

The treatment and allocation of risks in PPAs can also be biased toward some technologies. PPAs ideally specify which party will assume different risks. Otherwise, equity owners of the project are typically assumed to bear them. For example, PPAs may include fuel cost indexing provisions that protect developers of thermal projects against the risk of future fuel price volatility.

In some countries, many of these issues have been addressed through the development of standardized power purchase agreements that include provisions on how much the utility will pay for the power over a specified period of time. Where private power projects that use renewable resources have fared relatively well (such as India, Indonesia, and the Philippines), the terms of power purchases and other policies have been explicitly geared to the characteristics that distinguish renewables from conventional power sources. (See, for example, Box 7.)

Restructuring

The conditions and rates under which independent power producers can gain access to the transmission system and use it to "wheel" power for sale directly to electricity users affect the independent power producer's choice of technologies in grid-connected applications. Transmission access has the potential to stimulate development of new renewable power generation. Because renewable resources are location-specific, developers of renewable power generation depend on access to transmission lines to sell power to the grid. Moreover, transmission access gives renewable power developers the ability to sell power to locations where, and at times when, it is more highly valued than by the local utility.

Despite legal and physical access to transmission lines, however, renewable developers may not have equal access to transmission capacity because of unfavorable contract terms. Developers of intermittent generation may be charged more per kilowatt-hour to transmit power than their dispatchable competitors. Transmission access charges may be based on a generator's maximum rated capacity or what it actually generates during peak periods. Moreover, the site-specific nature of renewables may be a drawback under some transmission pricing schemes. Rates may be based on distance or contract paths regardless of actual transmission costs or the flow of electrons. To facilitate wind power development, several states in India charge 2% of the power transmitted for wind generators to gain transmission access. (Unfortunately, transmission system bottlenecks reduce the effectiveness of this policy in some states.)

Competition

Wholesale competition is not likely to favor renewables in bulk power markets. Compared with long-term bilateral power purchase agreements, short-term or spot markets make it more difficult to finance and develop renewable generation options. For one thing, renewable projects bidding into spot markets are harder to finance than generation projects with low capital costs. Lenders are reluctant to provide debt capital for renewable energy merchant plant projects. especially in countries where spot markets have yet to establish a track record. Since lenders require that power projects demonstrate steady, predictable cash flows to meet debt service requirements over several years, the revenue risk created by unpredictable spot markets effectively precludes financing.

Spot markets are particularly unfriendly to the development of "intermittent" renewable resources that generate power when the sun shines and the wind blows. Their prices may be high for a limited number of hours in a year and not necessarily when these intermittent renewable resources are available. The inability to generate power on demand is more of a drawback in spot markets, which place a high premium on generators that can assure power availability during peak periods. Because these resources cannot be dispatched on demand, the rules governing dispatch and payment in competitive wholesale markets are particularly important in determining their value. In contrast, developers of thermal plants can secure financing because they have greater control over when they sell to the spot market and because their lower debt load gives them less exposure to a prolonged slump in market prices.13

Retail competition is also likely to affect the ability of renewables to compete in bulk power markets in developing countries. The incentive to retain and attract customers that is created by retail competition makes electricity suppliers seek opportunities to minimize rates and to differentiate themselves from competitors. In the United States and parts of Europe. some retail suppliers are trying to differentiate themselves by marketing "green" (environmentally friendly) electricity generation. This market niche is, however, likely to be much smaller in developing countries because environmental consciousness is generally lower and electricity costs tend to loom larger in household or business budgets.

V. Conclusions and Recommendations

Making generalizations about how power sector reform will affect market prospects for renewables is complicated by the range of reforms, the characteristics of different power markets that renewables might enter, and the variation among countries' pre-reform conditions. Table 2 summarizes the key relationships between reforms and the different markets for renewables discussed in this paper.

Conclusions

Despite the difficulty in making generalizations, several conclusions can be drawn:

The implications of power sector reform for renewables depend on assumptions about the pre-reform "base case." Other than large-scale hydropower, there are few cases where renewables have made major in-roads into the bulk or distributed power markets of developing countries. With some exceptions, this experience is unlikely to change under a continuation of state-owned monopoly utilities.

Some power sector reforms enacted or contemplated in developing countries will improve market opportunities for renewable energy equipment suppliers and developers; others will not. At best, a better managed power sector will be in a position to weigh carefully new options for system expansion, especially using the distributed model. At worst, reforms that strengthen incentives to choose nonrenewable power sources represent not so much a retrenchment as a missed opportunity.

In general, prospects for renewables penetrating distributed markets are improved when fuel and tariff subsidies are eliminated, when accounting for transmission and distribution costs is separated, and when the distribution provider chooses modes of service extension on the basis of the lowest system cost.

Prospects for renewables in bulk power markets are less clear in the transition from public to private investment, since privatization's advantages (influx of new capital and breaking the state monopoly on power generation) are likely to be offset by its disadvantages (high discount rates and short time horizons leading to preference for thermal generation over more capital-intensive options).

The introduction of wholesale and retail competition is likely to hurt the prospects of renewables in the absence of countervailing policy interventions. Without an explicit GHG policy in developing countries, such as carbon values imposed on fossil fuels, bulk renewable capacity may increase in absolute terms but is unlikely to increase market share dramatically. Investments in demand-side renewables are not likely to be made without appropriate regulatory incentives. This finding is particularly important for power sectors that are small or have other characteristics that make the economic benefits of introducing competition relatively modest.

With respect to restructuring, the deployment of distributed resources will be determined by the ability of at least one player in an unbundled sector to capture system benefits.

Renewables are likely to play a larger role if power sector reforms encourage consideration of the distributed rather than a central station model. In the near term, renewables will be most successful in competing for off-grid customers and other distributed applications where system costs for generation, transmission, and distribution are high.

Power sector reforms have the greatest potential to improve the status quo in countries with large unelectrified populations. A privatized distribution company given exclusive access to an off-grid area can balance the returns of grid-connected and off-grid customers. It also can absorb market entry costs, achieve economies of scale in equipment and in operations and maintenance costs, exploit its existing network of local agents, and use its large cash flow to finance systems and absorb seasonal variations in customers' ability to pay.

Recommendations

The current period of power sector reform in developing countries will last for at least a decade. It offers both an opportunity and a danger for renewables. The opportunity is related to the sheer size of the various markets in which renewables can participate, and in some of which they enjoy a comparative advantage. The danger is that the rules governing reformed power sectors and markets will lock in conventional technologies. To realize the opportunity afforded by reform, stakeholders should consider the following recommendations.

Developing-country governments should evaluate the implications of specific reforms being considered with respect to incentives for technology choices.

To avoid potentially adverse environmental effects of introducing competition to the power sector, reformers should reassess specific reform packages being considered to ensure that modest economic gains are not made at the expense of locking in nonrenewable power generation. Mitigating measures should be concurrently implemented -- such as initiating funding for sustainable energy options, drafting wholesale market rules that not biased against renewables, and advocating regulatory policies that give retail service providers incentives to offer demand-side services.

Bilateral and multilateral assistance organizations should help developing-country governments design indigenous models for power sector structure, operation, and regulation that are environmentally sustainable.

Due to the lack of indigenous alternatives, developing countries tend to adopt both electricity technologies and policy frameworks from industrial countries. Successful institutional models for the power sector that have been pioneered in one country have been widely observed among developing nations. International donors should provide technical assistance in developing indigenous structural models and institutional mechanisms for sustainable energy development that are geared to the power sector characteristics of specific client countries. For example, many developing countries might be better suited to a distributed model of power sector expansion. The distributed utility model might call for a completely different sectoral structure than reform trends in OECD countries would suggest.

Developing-country governments should enact laws and regulations that clarify and strengthen the responsibilities of privatized distribution service providers for rural electrification.

Key decisions in the privatization process include drafting the terms of sale of a utility, establishing criteria for awarding bids, creating the distribution concession contract, and determining the subsequent regulation of the concessionaire. The whole sequence of decisions has a potentially significant effect on the incentives for rural electrification based on renewable energy.

Because government retains greater leverage over rural electrification prior to the majority ownership sale of the utility, it should specify at least some fundamental rural electrification requirements in any privatization bidding document it issues. Then all bidders could assess the associated costs and risks and could factor them into the dollar value of their bids. Beyond minimum requirements, bid evaluation criteria could include business plans for serving off-grid areas in a least-cost manner. Once the contract is awarded, the state could allow a higher return if the concession meets specified performance objectives relating to rural electrification.

Developing-country governments should clarify sources of funding for rural electrification as they reform their power sectors.

Regardless of what technologies are used to electrify rural areas, associated costs are generally higher than in urban areas. Developing-country governments should consider allocating a portion of the proceeds from the sale of public distribution systems to a rural electrification account that would become available to the new owners or other entities responsible for electrifying rural areas. There are many claims on these proceeds; it may make sense to combine rural electrification with other rural development initiatives.

To increase the competitiveness of off-grid options with grid extension, all current forms of public support and customer class cross-subsidies should be equally available. Moreover, the primary distribution provider should be informed that lack of progress in extending service will force the government to solicit bids from other parties to provide this service.

Power sector reforms should ensure that distributed resource options can compete fully to provide electricity services.

The distributed resource model allows grid-support, off-grid, and demand-side renewables projects to be valued fully. Improved cost accounting would enhance utility incentives to weigh grid extension against distributed resource options. Regardless of whether the utility is functionally unbundled, power sector reforms should foster careful evaluation of the generation, transmission, and distribution costs that can be avoided by distributed resource investments.

The distribution company should be required to collect information on area- and time-specific marginal costs, which would allow more accurate analysis of the cost-effectiveness of distributed applications of renewables. Time-of-use and area rates would give appropriate price signals to end-users for consideration of demand-side renewable options. Time- and location-differentiated rates could be used first in bringing service to currently unelectrified regions and then phased in for grid-connected regions.

Least-cost resource acquisition at the distribution level would ensure a level playing field among grid extension and various off-grid options. At a minimum, regulators should require distribution concessions to estimate their location-differentiated cost of service, including generation, transmission, and distribution costs. Each area (one served by a substation, for example) would have to cover its costs. This gives distribution companies an incentive to acquire off-grid resources if they are cost-effective compared with grid extension. Regulators may need to develop least-cost analytic procedures and provide training to utilities.

Regulation of retail electricity suppliers should create economic incentives that promote full consideration of renewable energy technologies on both the supply side and the demand side.

Regulators should craft retail rate formulas that are at least neutral with respect to generation technology. For example, regulators can eliminate fuel cost pass-through and other practices that treat the risks associated with various generating options differently. However, rate-making could go further. Regulators can create regulatory alternatives to cap prices and reduce retail suppliers' incentive to maximize electricity sales. Furthermore, regulators can design performance-based rate making can be designed to explicitly encourage the acquisition of target levels of renewable resources. Retail suppliers could be encouraged to develop a diverse portfolio of resources based on rate bonuses or penalties. Performance-based regulation can also create incentives for retail service providers to invest in demand-side management by decoupling profits from sales.

Power purchase agreements need to be crafted in ways that avoid biasing decisions against renewable energy technologies competing in bulk power markets.

Developing-country governments might draft and adopt model standard PPAs that provide incentives for the selection and operation of renewable energy technologies. Provisions might include:

- premium rates for projects whose environmental performance exceeds national standards
- payment terms (such as front-end loading) that do not discriminate against renewable energy options with comparable life-cycle costs to, but higher capital cost intensity than, thermal options; and
- explicit assignment of risks and liabilities associated with future environmental controls between power suppliers and purchasers.

As one example of the last provision, power purchase agreements could specify who will bear th risk of any climate policy, such as a carbon tax, that could increase a project's future operating costs. Although the timing and nature of such carbon restrictions are uncertain thus far, this risk i quite real, especially over the 40-year lifetime of thermal power projects. If carbon restrictions were imposed, both parties would have to agree to renegotiate the PPA.

Where transmission services become common carriers, all types of generation should have equal access to transmission capacity.

Transmission rate structures should not be biased against intermittent renewable capacity.

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Where transmission services become common carriers, all types of generation should have equal access to transmission capacity.

Transmission rate structures should not be biased against intermittent renewable capacity. Comparable transmission pricing would help overcome barriers to intermittent or low-capacity-factor renewables. Transmission cost structures should account for intermittency in a way that is fair to all types of generation. If the demand component of transmission charges is based on a generation facility's capacity equivalence (for example, an average level of coincident peak capacity output per month) rather than maximum rated capacity, then intermittent resources would pay more than their fair share of transmission costs. The energy component of transmission costs should be based on a significant fraction of total investment in the transmission grid.

Wholesale power markets should be required to consider the environmental characteristics of competing generators.

The calculus for determining generation dispatch priority should be based on social marginal costs -- that is, including fuel, variable operation and management, and external environmental costs. In short-term markets, the entity responsible for this would be the power pool manager. Social cost dispatch would strengthen incentives for merchant plant developers to choose technologies and fuels with low emission factors.

Realizing the Potential of Renewables

The future of renewable energy in a restructured and competitive electricity industry in the United States is currently subject to heated debate. While the interaction between power sector reform and renewables is rarely discussed in Asia, Latin America, and Africa, these regions are more likely to hold the key to the future of renewables because of burgeoning electricity demand and large populations unconnected to the grid. The massive investment in the power sector to be made in these regions holds the potential for enormous renewables markets. Whether this potential is realized depends on the path of power sector reform, which can either create new market opportunities for renewables or freeze them out. Timely interventions in the reform process by domestic policymakers, renewable energy trade groups, nongovernmental organizations, and other stakeholders would help to guide reforms in renewable-friendly directions.

*** FOOTNOTE SECTION***

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North America, Western Europe, Japan, Australia, and New Zealand.

Dennis Anderson and William Cavendish, Efficiency and Substitution in Pollution Abatement: Three Case Studies, World Bank Discussion Paper 186 (Washington, DC: World Bank,1992).

Anil Cabraal, Mac Cosgrove-Davies, and Loretta Schaeffer, A Best Practices for Photovoltaic Household Electrification Program, World Bank Technical Paper No. 234 (Washington, DC: World Bank, 1996); World Bank, Indonesia Policy and Operations Division, Staff Appraisal Report: Indonesia, Solar Home Systems Project, Report No. 15983-IND (Washington, DC: 17 December 1996).

Heidarian and Wu, Power Sector Statistics for Developing Countries, 1987-1991 (Washington, DC: World Bank, December 1994).

The factors driving power sector reform in developing countries are quite different than those in OECD countries. Developing countries need to attract private capital to invest in expanding and upgrading their power systems. They also recognize the need to improve managerial efficiency, accountability, and customer service. In contrast, power sector reforms in OECD countries are driven by the desire to lower electricity costs through competition.

John Besant-Jones, "The England and Wales Electricity Model--Option or Warning for Developing Countries?" Viewpoint (Washington, DC: Industry and Energy Department, World Bank, June 1996).

In the United States, this price is based on the costs that the utility avoids by not having to develop new capacity itself. Avoided costs, however, vary widely among utilities due to input assumptions, data availability, and analytic approaches.

Robert Bacon, Appropriate Restructuring Strategies for the Power Generation Sector: The Case of Small Systems, Industry and Energy Department Occasional Paper No. 3 (Washington, DC: World Bank, 1995).

Discounting is the opposite of accruing interest--with a positive discount rate, a dollar is worth more today than in the future.

John Nimmons et al., Legal, Regulatory, and Institutional Issues Facing Distributed Resources Development, NREL/SR-460-217891 (Golden, CO: U.S. Department of Energy, National Renewable Energy Laboratory, 1996).

Although hydropower has minimal air emissions, big dams have other ecological and social impacts that complicate the environmental implications of privatization in previously hydro-dominated power systems.

Paul Centolla, "Wind in Competitive Power Markets: How Market-Based Policies Can Incorporate Renewable Energy Benefits," presented at Wind Energy in a Restructured Electric Industry, Washington, DC, 1994.

BOX SECTION

Box 1: Common Power Sector Reforms

For purposes of this report, the term "reform" will be used as a proxy for a broad range of changes in the power sector that could include one or more of the following:

- forming a corporation and commercializing the management of public utilities;
- introducing private-sector management or ownership of generation, transmission, and distribution assets and operations;
- creating wholesale power markets in which independent power producers sell to the grid;
- separating generation, transmission, distribution, and retail services; and
- creating retail markets in which private entities compete to supply electricity services to end-use customers.

Box 2: An Alternative Model for Power Sector Expansion

Technologies appropriate for distributed generation include modular renewables (such as photovoltaics and small-scale wind turbines) and modular nonrenewable generation (such as fuel cells and gas micro-turbines).

Although the distributed utility model has been pioneered in the United States, its characteristics appear particularly well suited to conditions prevailing in many developing countries:

- uncertain demand for power in rural areas, suggesting an incremental approach to investment;
- high transmission and distribution costs;
- relatively low electrical demand per unit area;
- high energy losses in getting power to the user (for example, more than 20% loss in India); and
- unreliable interconnections and poor local power quality.

The distributed approach can help meet these challenges. Local demand peaks, which are often costly to serve, are reduced. Excess power can be sent to customers outside the immediate grid. Power quality can be improved. Finally, capital-strapped utilities can phase in needed investments. That is, local grids can be developed first and, when demand rises sufficiently, they can be connected to the transmission system.

Because the level of investment in power sector infrastructure is still small relative to the level needed to meet projected demand, developing countries could potentially leapfrog to a distributed utility model. The potential for this can be seen in countries where telecommunications systems have bypassed wires and leaped to cellular phones, and where information processing has skipped the mainframe stage and moved directly to personal computers.

Box 3: Rural Electrification

In many developing countries, governments often have required public utilities to extend the grid to rural areas -- without having tariff structures or collection ability to recover service costs. Rural electrification has thus often been implicitly or explicitly subsidized by urban electricity customers or by transfers from the national treasury. In some countries, grid extension has been closely associated with local politics, either in terms of promises made before elections to electrify, or even votes being delivered in exchange for electrification. Some utilities are reluctant to give up their political power, even though they lose money on every kilowatt-hour provided to rural customers. (Some industrial countries have also historically subsidized rural electricity services.) Because the ability to raise capital is limited, extension of the grid has proceeded slowly.

Box 4: Merchant Plants

Merchant plants are built with the understanding that they do not have specifically identified buyers to purchase their output at fixed prices over a long term (15-20 years). Instead, they sell into the market and receive whatever price it dictates for the particular day or hour.

The incentives facing merchant plant developers choosing between capital or fuel-cost-intensive generation technology are different than for plant developers with long-term sales contracts. Financing usually involves a greater percentage of sponsor equity (50% or more). This raises the cost of capital because equity capital is more expensive than debt capital.*

Because of the uncertainty over market prices and thus investment returns, merchant plant developers are likely to opt for less capital-intensive capacity than developers of dedicated capacity. Still, the merchant plant developer wants operating costs to be sufficiently low to assure a favorable (baseload) position in the dispatch order. The tension between the developer's incentives for minimizing capital cost and operating cost may be resolved by choosing natural gas generation where gas supplies are cheap.

J. Paul Forrester, "Wanted: A New Financing Model for Merchant Power Plants," Power Economics, Vol. 1, No. 1, February 1997, pp. 23-25.

Box 5: Argentina Rural Concessions Program

To promote the extension of services into rural areas, the Argentinean government has initiated the Electricity Supply Program for the Rural Dispersed Population in cooperation with participating provincial Regulatory Authorities. The program gives priority to photovoltaic panels, small windmills, hydraulic microturbines, and diesel-driven generators. The total estimated investment of $314 million will be shared, with 45% paid by users, 25% from provincial subsidies, and 30% from national subsidies.

The program grants competitive concessions to one or more private enterprises in each province on the basis of lowest subsidy required per supplied user, technical qualifications, and financial qualifications. The concession will run for 45 years divided into three periods of 15 years. At the end of each period the Regulatory Authority will call for a new bidding process, with the prevailing concessionaire having priority. Rates are negotiated between the concessionaire and Regulatory Authority for five-year periods. The concession shall be exclusive for users of up to 90 kilowatt-hours per month.*

It is too early to determine the effectiveness of this approach. As of late 1996, three provinces had at least begun the process of awarding concessions, with the remainder expected to do so by 2000. Two bids have been awarded. In each case there were four to five bidders, with a wide range in the bid values offered for combined rural and urban concessions. Concessionaires, who are established utilities elsewhere, are beginning with community applications in order to gain experience in their markets. The next stage will tender separate offers for the urban and rural markets, although the same bidder may bid for both.

A. Fabris and M. Servant, "Argentina Dispersed
Rural Population Electricity Supply Program," Secretaria de Energia, Buenos Aires, Argentina, 22 October 1996.

Box 6: How Ownership Affects the Cost of Wind Energy

The ownership and associated financial structure of wind energy projects has a significant effect on their levelized cost of energy. A U.S.-based cash flow analysis found that the most expensive option is independent power producer ownership with project financing. Public utility ownership with project financing is slightly (1%) less expensive, while public utility ownership with internal financing is 12% less expensive, and investor-owned utility ownership with corporate financing is the least expensive option (29% less expensive than IPP). The factors responsible for these differences are the cost of debt and equity capital, the fraction of debt in the capital structure, and the amortization period.* While the numerical results will differ, these ownership and finance structures are likely to have a similar effect on the relative cost of renewables in developing countries.

Ryan H. Wiser, "Renewable Energy Finance and Project Ownership," Energy Policy. Vol. 25, No.1 (1997), pp. 15-27.

Box 7: Policies for Renewably Generated Power Production in India

The Government of India's incentives to stimulate development of renewably generated power are among the most extensive in the world. The central government offers deep tax concessions, below-market financing, and other schemes designed to promote renewable power development. In several states, State Electricity Boards will buy power from renewable developers at quoted rates and allow them to sell power elsewhere using the transmission system. In February 1997, the central ministry announced that it expects 10% (1,000 megawatts) per year of new capacity additions to come from renewables.

Specialized programs and policies for renewables have stimulated their market penetration, but they also isolated renewables from mainstream power sector decisionmaking under the Ministry of Power. India's power sector reforms have proceeded largely independently of its policies for renewable energy. As power sector reforms and privatization move ahead, separate policies and subsidies for renewables will become difficult to maintain. In addition, the overall trend of devolution of political power to the states means that each state's reform policy will become more important.

*b243W

Renewables –
Prospects and Policy Reforms

A.K. Mangotra
Joint Secretary
Ministry of
Non-conventional Energy Sources

STRUCTURE OF PRESENTATION

- Indian Energy Scenario
- Renewables in India
- International Trends
- Policy initiatives required

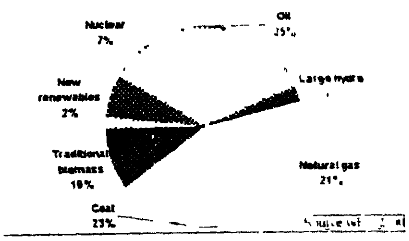
World Primary Energy Consumption - 1998

Source	Primary Energy (exajoules)	% Total
Fossil fuels	320	79.6
Oil	142	35.3
Natural gas	85	21.1
Coal	93	23.1
Renewables	56	13.9
Large Hydro	9	2.2
Traditional biomass	38	9.5
New renewables *	9	2.2
Nuclear	26	6.5
Total	402	100

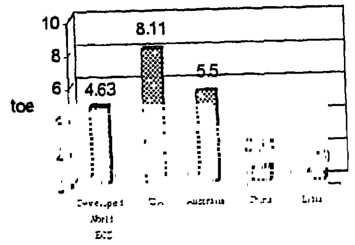
* Modern biomass SHP wind geothermal solar & marine

Source WEC 2000

World Primary Energy Consumption - 1998

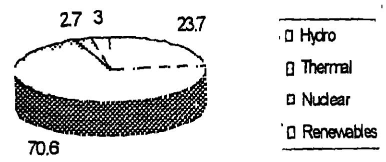


Energy consumption per capita



POWER IN INDIA

Total Installed Capacity 1,01,884 MW



Energy Characteristics In India

- Large Rural population
- Predominantly biomass used in rural areas
- Maximum energy for subsistence needs
- Low Energy efficiency devices
- Drudgery of women and children
- Domestic air pollution & health hazard
- In present climate change regime pressure to phase out traditional ways of energy production and utilization

Energy Consumption in India

- Non-commercial energy constitutes over one-third of total energy
- Three-fourths of total energy used in rural areas is in the domestic sector
- Traditional biomass- fuelwood, animal dung, crop residues account for over 90% of domestic energy used in rural India

Power Growth Perspective

- Peaking shortage – 14.8%
- Energy Shortage – 9.1% (By end of 9th Plan)
- Electricity demand growing @ 8% annually
- Capacity addition of 1,00,000 MW over the next 12 years
- Challenge is to meet the energy needs in a sustainable manner

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Historical Perspective

⇒ *1981* - **Commission for Additional Sources of Energy (CASE) set up in DST**

⇒ *1982* - **Department of Non-Conventional Energy Sources (DNES)**

⇒ *1992* - **DNES converted into a full fledged Ministry of Non-Conventional Energy Sources (MNES)**

⇒ **Only Country with an independent Ministry**

⇒ **IREDA set up in 1987 - only PSU**

MAJOR RENEWABLE ENERGY PROGRAMMES IN INDIA

➢RURAL ENERGY

- BIOGAS
- IMPROVED CHULHAS
- BIOMASS
- INTEGRATED RURAL ENERGY PROGRAMME

➢SOLAR ENERGY

- SOLAR PHOTOVOLTAICS
- SOLAR THERMAL
- SOLAR WATER PUMPS
- HYBRID SYSTEMS

Contd..

MAJOR RENEWABLE ENERGY PROGRAMMES IN INDIA

➢POWER GENERATION

- WIND POWER
- SMALL HYDRO POWER
- BIOMASS POWER
- SOLAR POWER

➢ENERGY RECOVERY FROM WASTES

- ENERGY RECOVERY FROM URBAN & INDUSTRIAL WASTES
- UNDP/GEF PROJECT ON DEVELOPMENT OF HIGH RATE BIOMETHANATION PROCESSES

Contd

MAJOR RENEWABLE ENERGY PROGRAMMES IN INDIA

NEW TECHNOLOGIES

- FUEL CELLS
- HYDROGEN ENERGY
- ELECTRIC VEHICLES
- GEOTHERMAL ENERGY
- TIDAL ENERGY
- ALTERNATE FUEL

INSTITUTIONS OF MNES

- INDIAN RENEWABLE ENERGY DEVELOPMENT AGENCY
- SOLAR ENERGY CENTRE
- CENTRE FOR WIND ENERGY TECHNOLOGY
- NATIONAL INSTITUTE OF RENEWABLE ENERGY
- NINE REGIONAL OFFICES

Potential And Utilization

(Decentralized Systems)

SOURCES/SYSTEMS	POTENTIAL	HARNESSED (As on 31.8.01)
BIOGAS PLANTS (Nos.)	12 M.	3.22 M.
IMPROVED CHULHAS (Nos.)	120 M.	33.9 M.
SOLAR PHOTOVOLTAICS	20 MW/Km^2	73 MW (8.5 lakh)
SOLAR THERMAL SYSTEMS	140 M. m^2	0.59 M. m^2

Contd.

Potential And Utilization

(Power Generation)

(MW)

SOURCES/SYSTEMS	POTENTIAL	HARNESSED (As on 31.8.01)
BIOMASS POWER	19,500	343
GASIFIERS		41
WIND POWER	45,000	1367
SMALL HYDRO POWER (Upto 25 MW)	15,000	1398
URBAN & INDUSTRIAL WASTES	1,700	16.2
SOLAR POWER		1.74
TOTAL		3166 94

Major Barriers & Constraints in Renewable Energy Promotion

- Technology reliability and performance
- Higher initial Investments
- Lack of level playing field
- Week institutional framework & delivery mechanism
- Week financing mechanism for renewable energy projects due to higher risk

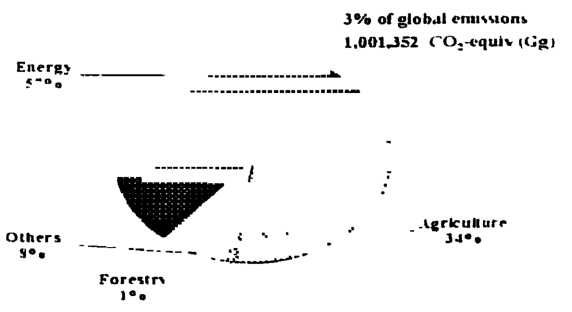
Contd

Major Barriers & Constraints in Renewable Energy Promotion

- Absence of Renewable Energy Legislation
- Green pricing and obligation to purchase from renewable energy sources
- Lack of uniform renewable energy guidelines policies in all States
- Strong private sector participation lacking

GHG Emissions in India(%)

(by source)



3% of global emissions

1,001,352 CO_2-equiv (Gg)

Source ALGAS

United Nations Framework Convention on Climate Change

- Main objective

  "Stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system."

- The Convention came into force on 21st March 1994. Over 180 countries including India have now become party to the agreement.

Kyoto Protocol

•Adopted at the Third Session of the Conference of the Parties in Kyoto, Japan on 11 December 1997.

An average reduction in GHG emissions by developed countries of, relative to 1990 levels, between 2008 and 2012	5 2 percent
European Union and several eastern European countries.	8 per cent
USA	7 per cent
Japan, Canada, Hungary and Poland	6 per cent

Flexibility Mechanisms under Kyoto Protocol

Article 6	Joint Implementation(between Annex-I countries)
Article 17	Emissions Trading (between Annex-I countries)
Article 12	Clean Development Mechanism (between Annex-I and non-Annex-I countries)

Article 12: Clean Development Mechanism

Joint Implementation between Annex-I and non-Annex-I countries

Purpose

i) To assist developing countries in achieving sustainable development

ii) To assist parties in Annex I in achieving compliance with their quantified emission limitation and reduction commitments

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Opportunities for CDM projects in renewable energy area

- Achievement made so far is only about 3 9 percent of the available potential
- CDM Projects could help in technology upgradation and in attracting investments
- CDM projects could provide opportunity for diverting government resources towards more socially oriented renewable energy sectors

Renewables in other countries

Australia :	Low interest loans for PV systems in remote areas
Austria :	Capital subsidies for biomass
Denmark	Capital subsidies of 15% to replace obsolete wind turbines
Germany	Guaranteed market with buy-back rates of 90% of average consumer-end prices for wind installations below 500 kW Low interest rates for renewables

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Renewables in other countries

Japan :	Rooftop PV systems upto 4 kW enjoy 50% capital subsidy for residential and 67% for commercial buildings besides guaranteed buy-back rates at consumer-end prices
Netherlands	Ambitious targets for future renewable energy use: 'Green Electricity' projects set up

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Renewables in other countries

Spain	Mixture of capital subsidy and guaranteed buy-back rates increased wind and SPV utilization
Sweden	Carbon tax on fossil fuels tripled biomass input to CHP systems
U K	NFFO pay premium rates for a guaranteed period (2.75-5.51p/kWh)
U S A	Tax credit of 1.5c/kWh for wind, solar, biomass or geothermal electricity stations not subject to federal income tax

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Renewable Energy Contribution

Country	Contribution (of TPES*)	Vision
Denmark	7.9%	35% by 2030
Germany	1.2%	25% by 2010
U K	0.7%	10% by 2010
Netherlands	1.4%	10% by 2020
Japan	2.1%	3% by 2010
India	3.0%	10% by 2012

* Total Primary Energy Supply
Source RE Policy Project [illegible]

Renewables and the Regulatory Regime

- Earlier only 14 States agreed for providing facilities for power from renewables
- Sudden enhancement in wheeling charges by Tamil Nadu & U P (from 2% to 15-20%)
- Regulatory regime not agreeing for preferential tariff & cess on coal and hydrocarbon for renewables
- Negotiations with SERCs are on in the new regime of electricity reformation

Legislative & Regulatory Support

- CERC to prepare tariff guidelines for renewable energy to be provided in the legislation
- to prescribe minimum quantity of power to be generated from renewables
- to provide for 'preferential' prices for renewables based on avoided cost of negative externalities
- Decentralized / off-grid generation and distribution not to be constrained by mainstream regulation

Contd...

Legislative & Regulatory Support

- Long term and uniform wheeling and banking policies to be provided legislative backing
- Model PPAs and contracts to secure timely revenue streams
- Amendment of Building Bye-laws to build in various renewable energy features like solar passive architecture, water heaters etc

Policy Initiatives/Interventions & enabling mechanisms to promote renewables

- Notification of formal policy with legislative framework for preferential tariffs, wheeling, banking, third party sale power evacuation facilities etc
- Fiscal incentives to be made more supportive of renewable energy sector
- Establishment of a National Renewable Energy Fund by charging cess in coal, hydro carbon and pollution sectors as 'sustainability tax'
- Creation of level playing field for renewables
- Role of the government in the restructured energy scenario

Policy Initiatives/Interventions & enabling mechanisms to promote renewables

- **Formulation of a comprehensive Renewable Energy Policy for:**
  - Meeting minimum rural energy needs
  - Providing Decentralized Energy systems
  - Generation & supply of Grid quality power
- Uniform policies across the country for power purchase, wheeling, banking, third party sale
- Renewables to be given a central role within the ambit of National Energy Policy process

Electricity Bill 2001 & Renewable Energy

On preparation of National Electricity Policy and Plan -

"Central Government shall prepare and notify a National Policy for Rural and Remote Areas permitting stand alone systems including those based on renewable and on other non-conventional energy sources in consultation with State Govts"

Electricity Bill 2001 & Renewable Energy

On Tariff Regulations –

"The appropriate Commission shall specify terms and conditions for the determination of tariff and shall be guided by the promotion of co-generation and generation of electricity from renewable sources of energy."

Electricity Bill 2001 & Renewable Energy

Powers/functions of State Commission –

- To promote cogeneration and electricity from renewable sources of energy by providing suitable measures for connectivity with the grid and sale of electricity to any person
- To specify, if considered appropriate, for purchase of electricity from such sources a percentage of total consumption of electricity in the area of supply of a distribution licence

Proposed enabling provisions for incorporation in Electricity Bill

- States to integrate renewables as a supply side option in their power development programmes
- SERCs should ensure a minimum energy quantity through renewables (say 10%) in purchase plans of T&D utilities
- CERC to formulate guidelines for promotion of renewables with preferential tariffs

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Proposed enabling provisions for incorporation in Electricity Bill

- Promotional measures for wheeling, banking and third party sale for grid-connected renewable power projects to be included
- Appropriate provisions including de-licensing to be made for decentralized/off-grid generation from renewables

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VISION - 2012

Goals

The medium-term goals, to the end of the Eleventh Five-Year Plan in 2012, are:

- Electrification of 18,000 remote villages
- Addition of about 10,000 MW of renewables based power.
- Creating about one million jobs in manufacturing, installation, and servicing of renewables

Contd

VISION - 2012

Goals

The medium-term goals, to the end of the Eleventh Five-Year Plan for decentralised systems by 2012, are:

- Improved cook stoves in 30 million households
- Setting up of 3 million family size biogas plants
- Deployment of 5 million solar lanterns and 2 million solar home lighting systems
- Solar water heating systems in a million homes

Energy and Poverty

Chapter one of

Energy & Development Report 2000: Energy Services for the World's Poor

Energy Unit of the World Bank's
Infrastructure Group and the Energy Sector
Management Assistance Programme

1

Reaching the poor in the age of energy reform

Penelope J Brook and John Besant-Jones

Throughout the industrial era investments to expand and improve energy services have been a mainstay of economic and social development policy in emerging and industrial countries alike. By expanding access to reliable sources of energy—gas, electricity, petroleum products—for agriculture, industry, commerce, and households, governments have primed growth in productivity and output. But in recent years the focus of their interventions has shifted from investing public funds in large-scale energy projects to mobilizing private investment and adopting commercial standards through structural, regulatory, and ownership reforms. Whatever the approach, the link between energy and economic development remains indisputable (World Bank 1994).

The link between energy programs and poverty alleviation is less well understood—and more likely to provoke debate and soul-searching among energy specialists. That access to better and cheaper energy services improves the welfare of the poor seems obvious. But how can we identify the less direct effects of changes in the sector on the poor—particularly the effects of recent sectoral reforms? And how can we weigh the effects on the poor of pro-growth, pro-efficiency reforms against those of direct interventions aimed at improving the poor's access to modern energy for consumption and productive uses?

Hard data to answer these questions remain in remarkably short supply. And the time for preparing this report was too short to commission empirical work to address this deficit (Several authors note useful directions for such research, however.) Instead, the report focuses on clarifying the following issues:

- What role access to efficient and sustainable energy services can play in strategies for reducing poverty, and what role liberalizing energy markets can play in improving this access.
- How programs for liberalizing energy markets can improve options for expanding access to energy services for the poor (supported by case studies).
- What the key challenges—and key energy policy instruments—are in strengthening support to the poor.

It is arguable that the poorest of the poor, who probably make up the majority of the estimated 2 billion people who lack access to modern energy, do not stand to benefit much from reforms targeted primarily at existing electricity and gas networks. Should governments maintain these growth-oriented sector policies, but focus more attention on social spending aimed at sharing their benefits more effectively with the poor? Are more thorough reforms needed instead, aimed at developing markets in a variety of energy services for households and communities beyond the reach of existing networks—and often at the margins of the cash economy? Or should more emphasis go to programs combining a variety of infrastructure services and community interventions, so as to reap synergies from both bundling infrastructure services and involving communities in service delivery? These questions will continue to stoke a healthy debate among energy and poverty specialists for some time. This report aims to provoke, and to cast light on, that debate.

Access to energy—and poverty alleviation

Poor households and communities typically rely on diverse sources of energy, using one fuel for heating, another for cooking or lighting, another for agricultural or other productive activities Often the real (per unit) costs of these alternative energy sources are high relative to those of electricity or gas delivered through networks to wealthier households Moreover, these energy sources often have high nonmonetary costs. When women and children spend many hours collecting firewood or dung for heating and cooking, for example, they have less time for education or for developing other productive activities. And the use of traditional energy sources can have serious health and environmental consequences.

In essence, meeting the needs of the poor for sustainable energy means finding technological and institutional innovations that lower the costs of obtaining and using energy services, and tailoring these services to the requirements of low-income households and communities. That requires some knowledge of how they currently obtain services—and of the nature of their demand for improved services (see chapter 2).

Energy services such as lighting, cooking, refrigeration, and power for electronics and motive force are provided most cheaply and conveniently, and with the least local pollution, when they are derived from electricity or gas delivered through networks. That is because the unit costs of energy from non-network sources are high relative to those of energy delivered through networks (see chapter 6). Moving from traditional to modern fuels can thus dramatically raise the effective incomes of low-income households.

But substantial barriers may prevent low-income households and communities from gaining access to modern energy services:

- Low-income households may be unable to fund the high costs of connecting to the networks (which run from US$50 for the simplest single-phase connection to hundreds of dollars for more conventional connections).
- The effective cost of access to electricity is increased by the additional cost of purchasing electric appliances and fittings (see chapter 2).
- Electricity and gas networks are costly to build and thus require high densities of energy demand to be viable. Since low-income areas have relatively low densities of energy demand, especially in rural areas, expanding networks to these areas is generally not viable without substantial subsidies (see chapter 5).
- Where no network exists, installing alternatives (such as a household photovoltaic cell) is costly (see chapter 11).
- Investments in nongrid technology are often quite lumpy, reducing options for incremental increases in the use of gas and electricity. Where photovoltaic systems are used, for example, the initial decision on the size of cell to be installed sets an upper limit on energy availability (see chapters 10 and 11).
- Sustainable improvement in energy services requires not just investing in technology, but also developing commercial mechanisms for handling the relationship between suppliers and customers—from billing and payments to responding to customer complaints. Traditional mechanisms for handling the interface with customers are often ill suited to poor households in informal settlements (which may, for example, lack a formal address) or small and dispersed rural communities (see chapter 6).
- Households' ability to commit to new connections and pay for service depends not only on the affordability of the service but also on access to credit. Financing can be a major barrier for households that operate at least in part outside the cash economy or lack traditional forms of collateral.
- In the transition economies of Europe and Central Asia low-income households that historically received highly subsidized energy services struggle to pay tariffs set closer to cost recovery levels (see chapters 3 and 8).

For policymakers wanting to improve services for the poor, the critical question is what kinds of policies and projects will be most successful—and most cost-effective—in knocking down these barriers. The more successful policies are in this, the less need there will be for subsidies to bridge the gap between service cost and households' ability to pay (see chapter 7).

The task for policymakers is not to pick winning technological and commercial innovations.

Has energy market reform helped the poor?

Intentionally or not, developing country energy policies often have elements likely to block or distort efforts to help the poor. Many traditional policies have been built on the implicit assumption that the demand characteristics of low-income energy users are similar to those of higher-income consumers. For example, it is presumed that all consumers will be best served by connections to conventional electricity grids providing twenty-four-hour access at standards approximating those in developed countries. So policies for expanding access have often centered on universal service obligations for incumbent or new utilities, accompanied by cross-subsidies ostensibly aimed at improving affordability for the poor but regressively favoring higher-income users, and exclusivity provisions protecting these otherwise unsustainable cross-subsidies. In addition, policies have emphasized network expansion, probably at the cost of non-network alternatives—if only because of monopolies granted to network owners unfamiliar with these alternatives.

The past decade has seen a revolution in energy policy in developed and developing countries. In a growing number of countries traditional public investment projects to reinforce and expand electricity and gas networks are being supplemented or replaced by sector reforms aimed at enhancing competition, reforming regulation, and securing a greater role for the private sector in financing and managing power generation and gas and, increasingly, distribution. The maps on the front and back inside covers show reform "scorecards" for the power and oil and gas sectors, based on a 1998 survey of 115 developing countries. This survey focused on six key reform steps in each sector—from commercialization and market restructuring to regulatory reform and privatization. The results show that the power sector in these countries is still dominated by state-owned monopolies. In the oil and gas sectors the maps show very low levels of reform in downstream oil and gas, which is often accompanied by heavily subsidized prices and untapped potential for markets in such petroleum fuels as liquefied petroleum gas (Bacon 1999).

But private sector involvement in energy has been increasing. Between 1990 and 1999 seventy-six developing countries introduced private participation in their electricity and gas sectors by awarding more than 700 projects and divestitures of shareholdings in electricity and gas enterprises. These transactions involved private investments totaling almost US$187 billion.[1] While middle-income developing countries have led this revolution, low-income countries also have been active participants (figures 1 and 2).

Despite the experience gained in energy reform, advances in generation technologies (conventional and nonconventional), and institutional and financial innovations in providing energy to low-income areas, the reforms have made little impact in improving energy services to the poor. They have focused on networks serving better-off users, generally neglecting institutional and market constraints to serving the poor.

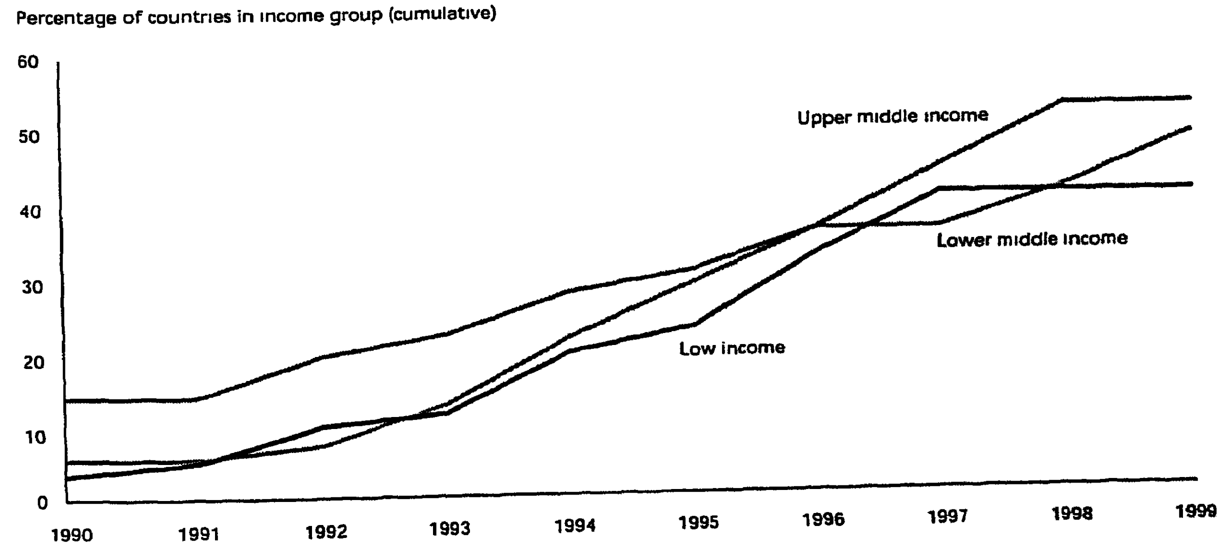
Policymakers reforming energy markets need to focus more on protecting and promoting the interests of the poor. In particular, they need to find ways of providing market and regulatory incentives that motivate private energy suppliers to extend access, improve service reliability, and help with payment difficulties. The record on this score from the privatization of electricity distribution in developing countries—predominantly in Latin America, for urban and periurban areas—is mixed. But the Latin American experience also shows that there is scope for helping the poor when electricity distribution is passed to the private sector (see chapters 9 and 10).

Energy policies for alleviating poverty

Across the energy sector, critical challenges remain: How to ensure that projects and policies intended to improve national welfare, particularly the welfare of the poor, achieve their aims? And how, in a sector characterized by both great diversity in services and complex links between service and poverty, to identify the kinds of interventions most likely to yield large and lasting benefits for the poor?

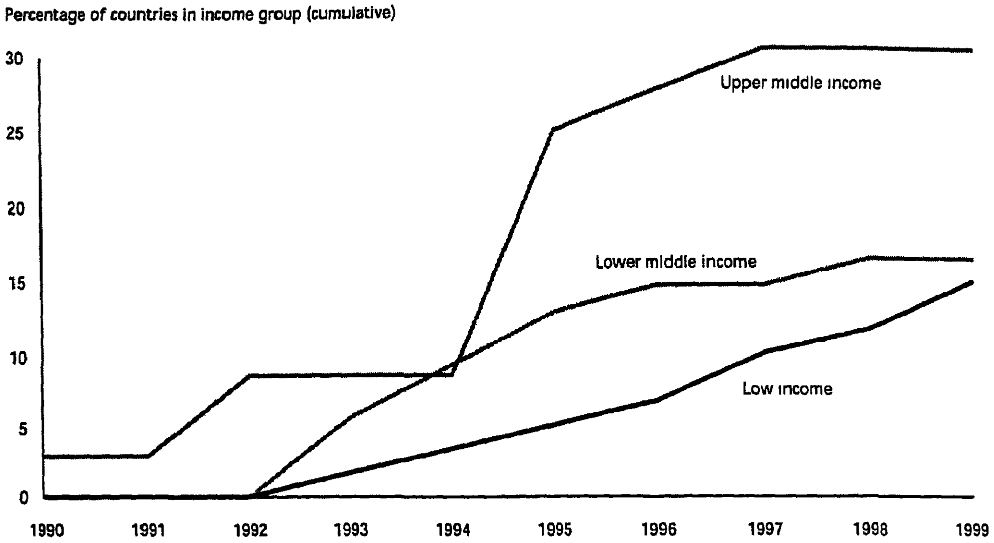
The task confronting policymakers is not to pick winning technological and commercial innovations (seldom an

Figure 1 **Developing countries with electricity projects involving private participation, 1990–99**



Note Country groupings are based on the income categories defined in World Bank 1999
Source. World Bank, PPI Project Database.

Figure 2 **Developing countries with gas projects involving private participation, 1990-99**



Note. Country groupings are based on the income categories defined in World Bank 1999 Gas projects include only transmission and distribution
Source World Bank, PPI Project Database.

area in which they have much comparative advantage), but to establish an environment with strong incentives for innovation in delivering energy services that meet the demands of users. New generation and distribution technologies and easily replicable models for community mobilization are essential to improving services for the poor, but will not develop in a hostile institutional environment.

The key tools at the disposal of governments as they try to open opportunities for "pro-poor" innovations are institutional ones (see chapter 12). They include choices about market structure and ownership (where and how competition and entry will be allowed and supported), regulation (what the prerequisites for, and mode of, regulatory intervention will be), and pricing (interventions in tariff structures, and fuel taxation). In efforts to help the poor enter the market for better energy services, tools are likely to include not only subsidy policy but also liberalization of financial markets to ease access to credit.

The chapters that follow focus both on policies for liberalizing energy markets and on policies and projects aimed directly at improving energy services for the poor—through subsidies and through investments in pilot or demonstration projects that increase market penetration for promising new technologies.

The report also provides resources for practitioners in energy and poverty: a review of developments in private financing of energy infrastructure in developing countries during the 1990s, a list of selected readings, and a list of World Bank Group contacts in the energy sector.

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Note

1 These data are from the World Bank's Private Participation in Infrastructure (PPI) Project Database For more details on developments in the gas and electricity sectors, and on the database, see part 2

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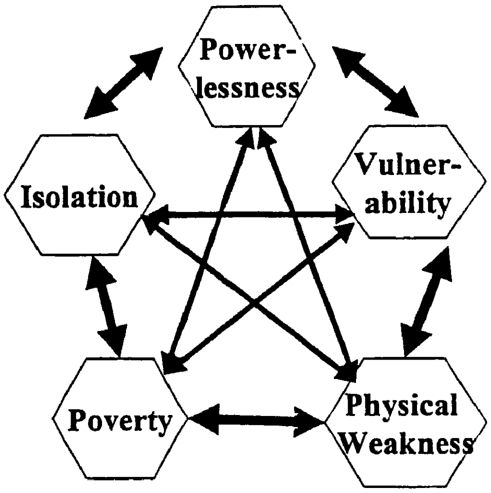
Energy reforms & poverty reduction

IAS Officers Training Programme on
Reforms in the Energy Sector
October 18, 2001

Dimensions of poverty

- Physical weakness - under-nourishment, ill health, disability
- Isolation - physical remoteness, ignorance, lack of access to basic services & information
- Income poverty - low level of income & wealth
- Vulnerability - increased exposure to contingencies, danger of situation worsening)
- Powerlessness - inability to cope, adapt, choose

The "deprivation" trap



Power-lessness

Vulner-ability

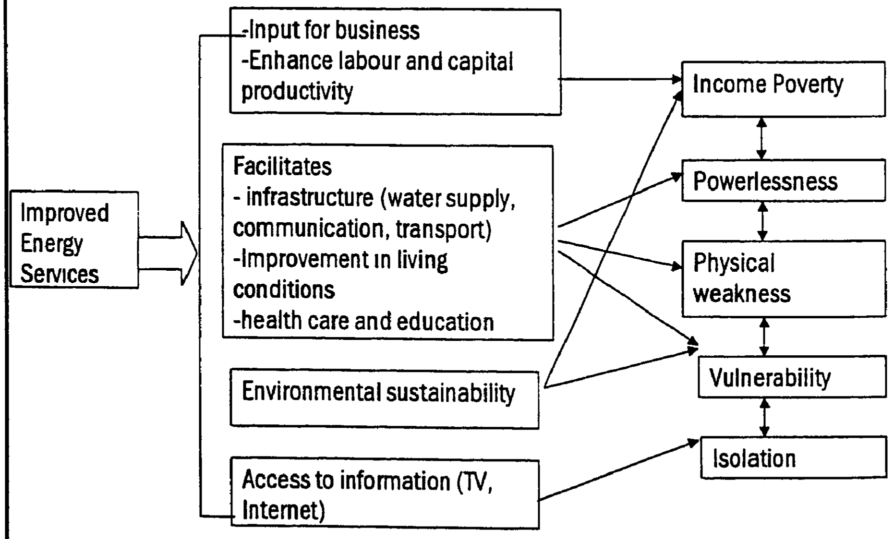
Isolation

Physical Weakness

Poverty

Chambers, 1983

Energy-poverty linkages



Improved Energy Services

-Input for business
-Enhance labour and capital productivity

Facilitates
- infrastructure (water supply, communication, transport)
-Improvement in living conditions
-health care and education

Environmental sustainability

Access to information (TV, Internet)

Income Poverty

Powerlessness

Physical weakness

Vulnerability

Isolation

Energy a Basic Need

Tajikistan: reduced access to electricity

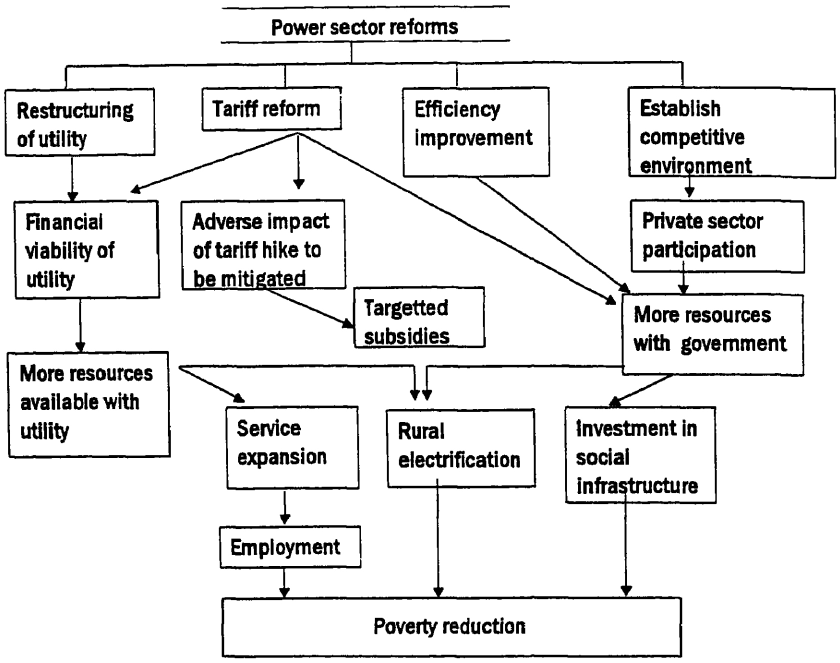
- Post-war: electricity supply erratic, < 2hours a day
- Energy : a basic need for space and water heating, water abstraction, cooking
- Increase in dependence on bio-fuels and diesel - monetary and non-monetary costs
- Opportunity cost of time:
  - gathering fuelwood & agricultural biomass: 15 days in a year
  - cooking: 5 hours each day
  - collecting water: 3-25 km trips
- Economic opportunities lost
  - Agricultural productivity- ↓ 20-25%
  - Other business
- Education- ↓school enrollment esp. during winter
- Health care: ↓ delivery of services

Energy reforms: dimensions

- Restructuring
  - unbundle, promote competition, privatise
- Regulatory framework
  - Protect interests of consumer groups
  - Provide level playing field to all suppliers
- Pricing reform
- Efficiency improvements

Will reform provide improved energy forms to those who do not now have access to it

Would reform make improved energy forms cheaper for the poor who already have access to it



Power sector reforms

Restructuring of utility

Tariff reform

Efficiency improvement

Establish competitive environment

Financial viability of utility

Adverse impact of tariff hike to be mitigated

Targetted subsidies

Private sector participation

More resources with government

More resources available with utility

Service expansion

Rural electrification

Investment in social infrastructure

Employment

Poverty reduction

Energy consumption in Indian households: some facts

- 90% of India's rural households use firewood or dung cake as the primary source of energy for cooking and heating.
- Less than 2% of rural households use LPG as the main cooking fuel
- 30% of urban households - use LPG, kerosene and firewood
- LPG use is substantial only among the highest income class in urban households (60%)

Impacts of dependence on biomass fuels

- Harvesting & collection of fuels
  - Time and effort in collection (upto 4-5 hours spent mainly by women and children
  - Money spent by urban households
  - Aggravates forest degradation
  - As forests degrade, coping strategies with harmful effects
- Combustion of fuels
  - Indoor air pollution -health hazards

Government Initiatives

- Subsidies on kerosene, LPG, electricity
- Improved cook-stoves
- Rural electrification
- Renewable energy technologies

Energy Subsidies

- PDS kerosene -- subsidised by about 45%
- LPG --- subsidised by about 30%

Problems

- Poor targetting
- Leakage of subsidy
- Restrictive - by limited availability
- Breeds inefficiency
- Biofuels apparently available at zero cost

Subsidy design crucial to
maximisation of poverty alleviation impacts

Improved cookstoves

- 33 million (target of 120 million)

Issues

- Socio-cultural factors overlooked
- No consultation with local communities
- Top-down target-based approach, no service orientation
- Poor quality and maintenance support
- Low priority for the block and the users
- Lack of awareness of benefits

Rural electrification

- 5 out of 6 million villages electrified

Problems

- The concept of "electrified" village
- Free supply in some states
- Flat rate pricing based on HP ratings
- Cross subsidization

Cost of supply and tariff charged (Paise/kWh)
1999/2000 All India average

Average Cost	Industry	Commercial	Agriculture	Domestic
280.9	352.1	353.9	24.8	149.7

Equity concerns

Chile: Efficient private solutions to rural electrification

Principles of programme design

- Decentralised decision making
  - Local communities→Municipalities →Local distribution companies → Regional government →CNE
- Joint financing
  - State, Electricity companies, Users
- Competitive selection of
  - Project
  - Distribution company
  - Region
- Appropriate technologies

% rural population with access to electricity
52% in 1992 → 76% in 1999

Barriers to use of modern energy forms

- Limited availability of modern fuels
- High supply costs --- where demand is low
- No consultative process in designing and implementing projects
- Initial cost of connection
- Affordability & WTP

Reaching the poor through energy reforms

- Energy pricing
  - Market-determined pricing
  - Targeted subsidies, income transfers
  - Minimise cross-subsidies
- Enabling mechanisms
  - Subsidy on initial / connection cost
  - Infrastructure for use of modern fuels
  - Access to micro credit
- Complementary infrastructure
  - Water and sanitation
  - Healthcare and education
- Pro-poor policy and institutional setting

Coal Sector

Coal and lignite

At a glance

- India's proven coal reserves of 82 396 MT (million tonnes) constitute seven per cent of total world proven reserves. Lignite reserves in the country have been estimated at 30 322 MT.
- India produced about 300 MT of coal and 22 MT of lignite in 1999/2000, and is the third largest coal producer in the world.
- National coal companies account for 98% of the country's coal production of which the Coal India Limited accounts for 88% and Singareni Collieries Company Limited for 10%.
- Indian coal has high ash content and low calorific value. The quality has declined further with increase in opencast mining.
- Washing of coal (to separate ash and coal) is difficult due to the presence of near gravity impurities. Also the existing coking coal beneficiation facilities are old and have low unit capacity.
- Given the limited scope for beneficiation, users of prime coking coal are compelled to turn to imports. Non-coking coal has also begun to be imported on the grounds of transportation logistics as well as against export entitlements. Over 15.6 MT of coal was imported in 1998/99.
- Though productivity (in terms of OMS [output per man-shift]) has improved considerably, particularly in opencast mines, the OMS in India is still less than one-twentieth that in Germany and USA.
- The pricing and distribution of all coal and coal products were deregulated in phases and the process was completed on 1 April 2000.

Reserves and production

The Geological Survey of India has estimated India's proven coal reserves at 82 396 MT (million tonnes), which was approximately seven per cent of the total world proven reserves as on 1 January 2000 (Table 1.01). India's total coal reserves are estimated at 211 594 MT, of which nearly 86% are non-coking coal reserves (Table 1.02).

Lignite reserves in the country have been estimated at 30 322 MT. Of this, 26 753 MT is in Tamil Nadu and Pondicherry, the rest in Gujarat and Rajasthan with small quantities in Kerala and Jammu and Kashmir (Table 1.03).

India is the third largest coal producer in the world. The CIL (Coal India Limited) and its subsidiaries are the major producers of coal, contributing approximately 86% of the coal produced in India. Through a sustained programme of investment and greater application of modern technologies, it has been possible to raise the production of coal from 100 MT in 1975/76 to 300 MT in 1999/2000.

The demand for energy is rising by the day, and the issue of energy security is paramount in the coal industry. Thus, it is important to address issues regarding the exploitation technologies and quality of coal mined, adequacy of environmental and resource utilization policies, and the legislative set-up for the sector.

Location and quality of resources

The major coalfields of the country are situated in Bihar, West Bengal, Assam, Madhya Pradesh, Orissa, Maharashtra, Andhra Pradesh, and some parts of Uttar Pradesh.

Indian coal is generally of low quality with high ash content and low calorific value. It exists predominantly in thick seams (approximately 70% of coal reserves are locked up in seams over 3.5-m thick and of this, 58% is in seams over 5-m thick) interbanded with extraneous matter. These seams are also complex with a multiplicity of coal horizons (20–25 in Jharia, 30–36 in Karanpura, and 10 in Raniganj).

Since some of the major consumption sites are located at a distance from the reserves, an enormous burden is placed on the transport infrastructure (Map 1).

The best quality of metallurgical coal is found in the mines of Jharia (Bihar) and in some mines in Raniganj (West Bengal). Before nationalization, mines in these areas were subjected to large-scale indiscriminate exploitation. As a result, the area is heavily built-up, and millions of tonnes of good quality coal has been left in pillars. Large areas of the Jharia and Raniganj mines have fires raging in them. Thus, mining coals in these areas is complicated, and the production of coal has steadily declined over the past few years.

The potential areas and new finds with good quarriable prospects, identified during the Eighth Plan period, are located in East Bokaro, South Karanpura, and Sohagpur coalfields for metallurgical coal; Birbhum, Sohagpur, Mand–Raigarh, Tatapani–Ramkola, and Korba for superior grade non-coking coal; and Talcher, Korba, Rajmahal, and Auranga coalfields for inferior grade non-coking coal.

The quality of power grade coal has deteriorated over the years. The power plants largely receive E, F, and G grade coals containing large amounts of ash and shale. As per the notification of 19 September 1997, power plants located in urban centres, sensitive areas, or critically polluted areas, or more than 1000 km from the source of supply are not to use coal with more than 34% ash content. This order is already applicable to some of the power stations in the vicinity of Delhi and Mumbai. Since adequate quantity of the requisite quality of coal is not available domestically, some consumers have already begun to import coal.

With regard to the issue of beneficiation of coal, washing of Indian coal is difficult because it contains near gravity impurities, making it hard to separate the ash from coal. As per the Altekar Committee recommendations, the desired level of average ash content in the washed coking coal for steel plants is 17% (±0.5%). The existing washeries were expected to modify and retrofit their equipment to maintain the desired level of ash. However, this has not happened, and the steel industry has become increasingly dependent on imports.

The quality can possibly be improved by blending imported and domestic coal. However, the infrastructure requirements for blending coal may be a constraint with the existing consumers. Selective mining using surface miners has shown great potential for improving quality in a couple of mines. This needs to be implemented on a large scale to be effective.

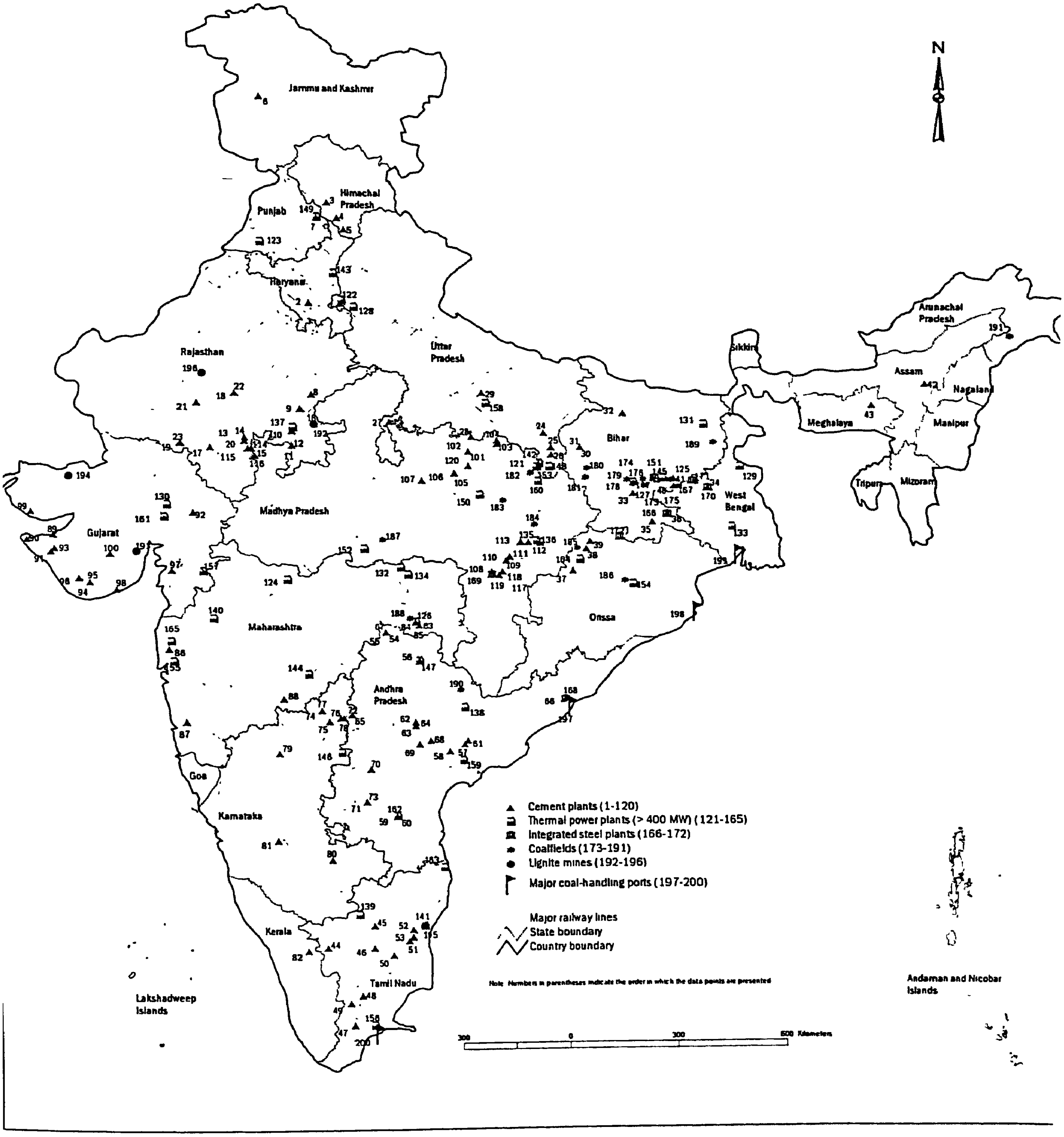
Demand estimates and production targets

The Planning Commission had assessed the demand for coal at 412 MT in 2001/02, 545 MT in 2006/07, and 775 MT in 2011/12 (corresponding to the low hydro-generation and high liquid-fuel-based generation of power) (*Ninth Five-Year Plan 1999–2002*). The corresponding production levels were estimated at 370.6 MT, 499 MT, and 672 MT for the respective years. This demand was reassessed at 370.80 MT (excluding 7.70 MT of middlings) for 2001/02 during the mid-term reassessment of the Ninth Plan. The overall indigenous coal production was also revised to 359.60 MT for 2001/02. The demand estimated for each year of the Ninth Plan is given in Table I.

Table I Annual demand as assessed by the Planning Commission for the Ninth Five-Year Plan

Year	*Demand* (million tonnes)
1997/98	323.40 (6.80)
1998/99	325.38 (7.50)
1999/2000	311.83 (3.00)
2000/01	333.85 (5.02)
2001/02	370.80 (7.70) (provisional)

Note Figures in parentheses are for middlings
Source Ministry of Mines and Minerals (1999)



Map 1 Coalfields and coal consuming industries (August 2000)

Sources
1 Survey of India, Dehra Dun
2 Central Electricity Authority, New Delhi
3 Central Board for Irrigation and Power, New Delhi
4 Coal India Limited, Calcutta
5 Cement Manufacturer's Association, New Delhi

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Map 1. Coalfields and coal consuming industries (data)

Cement plants: location and capacity

Sl no.	*Cement plants*	*Location*	*Capacity (thousand tonnes)*
1	CCI Ltd	Tughlakabad, Delhi	500
2	CCI Ltd	Charkhi Dadri, Bhiwani, Haryana	172
3	ACC Ltd	Barmana, Bilaspur, Himachal Pradesh	1938
4	Guj Ambuja	Darllaghat, Solan, Himachal Pradesh	960
5	CCI Ltd	Rajban, Sirmaur, Himachal Pradesh	200
6	J&K Cements	Khrew, Baramullah, Jammu & Kashmir	200
7	Guj Ambuja	Ropar, Roopnagar, Punjab	1040
8	Jaipur Udyog	Sawai Madhopur, Rajasthan	1000
9	ACC Ltd	Lakheri, Bundi, Rajasthan	322
10	Shriram Cement works	Sriramnagar, Kota, Rajasthan	200
11	Manglam Cement	Morak, Kota, Rajasthan	400
12	Neer Shree	Morak, Kota, Rajasthan	700
13	Birla Cement works	Shambhupura, Chittorgarh, Rajasthan	1000
14	Chittor Cement Works	Chittorgarh, Rajasthan	1400
15	JK Cement works	Nimbahera,Chittorgarh, Rajasthan	1540
16	J K Cement Works	Mangrol Kota, Rajasthan	210
17	JK Udaipur Udyog	Shaktinagar Udaipur, Rajasthan	900
18	Shree Cement	Bangur Nagar, Beawar, Rajasthan	3500
19	Lakshmi Cement	Banas/Sirohi road, Sirohi, Rajasthan	2230
20	Aditya Cement	Shambhupura, Chittorgarh, Rajasthan	1000
21	DLF Cement	Rabriyawas, Pali, Rajasthan	1400
22	Raj Cement	Beawar, Rajasthan	1240
23	Binani Cement	Sirohi, Rajasthan	1650
24	UP state Cement Corp.	Chunar, Mirzapur, Uttar Pradesh	1680
25	UP state Cement Corp.	Churk, Sonebhadra, Uttar Pradesh	475
26	UP state Cement Corp.	Dalla, Sonebhadra, Uttar Pradesh	432
27	Diamond Cement	Jhansi, Uttar Pradesh	500
28	ACC Ltd	Tikaria, Banda, Uttar Pradesh	600
29	Birla Cement	Raebareli, Uttar Pradesh	360
30	Kalyanpur Cement	Banjari, Rohtas, Bihar	1000
31	Rohtas Industries Ltd	Dalmianagar, Rohtas, Bihar	620
32	Sone Valley Portland	Japla, Patna, Bihar	254
33	Khalari Cement	Khalari, Ranchi, Bihar	109
34	ACC Ltd	Sindri, Dhanbad, Bihar	305
35	ACC Ltd	Jhinkpani, Singhbhum, Bihar	635
36	TISCO	Jojobera, Tatanagar, Bihar	1430
37	IDCOL Cement Ltd	Bardol, Bargarh, Orissa	960
38	L&T Cement	Jharsuguda, Sambalpur, Orissa	700
39	OCL India	Rajgangpur, Sundergarh, Orissa	1001
40	Damodar Cement	Madhukunda, Purulia, West Bengal	270
41	Birla Corp. Ltd	Durgapur, West Bengal	600
42	CCI Ltd	Bokajan, Karbi-Anglong, Assam	200
43	Mawmluh Chera Cement	Cherrapunji, Shillong, Meghalaya	200
44	ACC Ltd	Madukkarai, Coimbtore, Tamil Nadu	810
45	India Cements Ltd	Sankari west, Salem,Tamil Nadu	600
46	Chettinad Cement	Puliyur/Karur, Trichy, Tamil Nadu	600
47	India Cements Ltd	Talaiyuthur/Shankarnagar, Nellai Kattabo, Tamil Nadu	1100
48	TN Cements Corp.	Rajapalayam/Alangulam,Kamarajar, Tamil Nadu	400
49	Madras Cements Ltd	Virudhunagar/RS Rajanagar, Kamarajar, Tamil Nadu	750
50	Dalmia Cements (B) Ltd	Dalmiapuram, Truchirapally, Tamil Nadu	1030
51	TN Cements Corp.	Ariyalur, Trichy, Tamil Nadu	500
52	Madras Cements Ltd	Pennadam/Alathiyur, South Arcot, Tamil Nadu	900
53	India Cements Ltd	Dalavoi, Perambudur, Tamil Nadu	900
54	ACC Ltd	Mancherial, Adilabad, Andhra Pradesh	340
55	Orient Cement	Mancherial, Adilabad, Andhra Pradesh	1180
56	Kesoram Cements	Ramagundam, Karimnagar, Andhra Pradesh	900
57	Andhra Cements	Vijaywada, Andhra Pradesh	240
58	Kistna Cement	Kistna, Guntur, Andhra Pradesh	214
59	India Cements Ltd	Yerraguntla, Cuddaph, Andhra Pradesh	500
60	India Cements Ltd	Chilamkur, Cuddapah, Andhra Pradesh	1000
61	Madras Cements	Jayantipuram, Krishna, Andhra Pradesh	1100
62	Raasi Cement	Vishnupuram/Wadapally, Nalgonda, Andhra Pradesh	1800
63	Priyadarsani Cement	Kodad/Ramapuram, Nalgonda, Andhra Pradesh	600
64	Sri Vishnu Cement	Dondapadu/Sitapuram, Nalgonda, Andhra Pradesh	1000
65	CCI Ltd	Tandur,Rangareddy, Andhra Pradesh	1000
66	Andhra Cements	Vishakhapatnam, Andhra Pradesh	500
67	CCI Ltd	Adilabad, Andhra Pradesh	400
68	Andhra Cements	Dachepalli/Nadikude, Guntur, Andhra Pradesh	500
69	KCP	Macherla, Guntur, Andhra Pradesh	400
70	Panyam Cements	Bugganipalle, Kurnool, Andhra Pradesh	531
71	L&T Cements (AP)	Tadpatri, Anantapur, Andhra Pradesh	2000
72	India Cements	Tandur, Rangareddy, Andhra Pradesh	900
73	Zuari Cement	Tadpatri, Anantapur, Andhra Pradesh	1700
74	HMP Cements Ltd	Shahabad, Gulbarga, Karnataka	476
75	ACC Ltd	Wadi, Gulbarga, Karnataka	2005
76	Vasavadatta Cement	Sedam, Gulbarga, Karnataka	500
77	Rajashree Malkhed	Malkhed, Gulbarga, Karnataka	2000
78	CCI Ltd	Kurgunta, Gulbarga, Karnataka	200
79	Kanoria Inds Ltd	Bagalkot, Bijapur, Karnataka	330
80	Mysore Cements Ltd	Amasandra, Tumkur, Karnataka	570
81	Visvesvaraya	Bhadrawati, Bhadrawati, Karnataka	100
82	Malabar Cements Ltd	Palghat, Palghat, Kerala	420
83	L&T Cements	Korpana/Awarpur, Chandrapur, Maharashtra	2550
84	Manikgarh Cement	Korpana/Manikgarh, Chandrapur, Maharashtra	1500
85	ACC Ltd	Chanda, Chandrapur, Maharashtra	620
86	Shree Digvijay	Sewree, Raigarh, Maharashtra	200
87	Narmada Cement	Zadgaon, Ratnagiri, Maharashtra	333
88	Rajashree Hotgi	Hotgi, Sholapur, Maharashtra	1200
89	Shree Digvijay	Sikka, Jamnagar, Gujarat	1025
90	Dwarka	Dwarka, Dwarka, Gujarat	277
91	HMP Cements Ltd	Porbandar, Porbandar, Gujarat	198
92	Sevalia	Sevalia, Kheda, Gujarat	215
93	Saurastra Cement	Ranavav, Gujarat	1164
94	Ambuja Cement	Kodinar, Amreli, Gujarat	1000
95	Guj. Ambuja	Kodinar, Amreli, Gujarat	2000
96	Gujarat Sidhee	Tal-Veraval, Junagarh , Gujarat	1200
97	Narmada Cement	Magdalla, Surat, Gujarat	667
98	Narmada Cement	Jafrabad, Amreli, Gujarat	400
99	Tata Chemicals	Mithapur, Jamnagar, Gujarat	440
100	L&T Cem	Pipavav, Amreli, Gujarat	4000
101	Satna Cement Works	Satna, Madhya Pradesh	750
102	Birla Vikas	Satna, Madhya Pradesh	800
103	Jaypee Cement	Jaypee nagar, Rewa, Madhya Pradesh	2500
104	Jaypee Cement	Bela, Rewa, Madhya Pradesh	1500
105	Malhar Cement	Malhar, Satna, Madhya Pradesh	2000
106	ACC Ltd	Kymore, Panna, Madhya Pradesh	1400
107	Diamond Cement	Narsingarh, Damoh, Madhya Pradesh	1025
108	ACC Ltd	Bilaspur/Jamul, Durg, Madhya Pradesh	1580

Map 1 continued

Sl no.	Cement plants	Location	Capacity (thousand tonnes)
109	CCI Ltd	Mandhar, Raipur, Madhya Pradesh	380
110	Century Cement	Tilda, Raipur, Madhya Pradesh	1200
111	Ambuja Cement Easter	Bhatapara, Raipur, Madhya Pradesh	1800
112	CCI Ltd	Akaltara, Bilaspur, Madhya Pradesh	400
113	Raymond Ltd	DGopalnagar/Akaltara, Bilaspur, Madhya Pradesh	2240
114	Vikram Cement	Jawad Road, Mandsaur, Madhya Pradesh	1500
115	Vikram Super Cement	Jawad Road, Mandsaur, Madhya Pradesh	1000
116	CCI Ltd	Neemuch, Mandsaur, Madhya Pradesh	400
117	TISCO	Sonadih, Raipur, Madhya Pradesh	300
118	L&T Cements	Simga/Hirmi, Raipur, Madhya Pradesh	1450
119	Grasim Cement	Grasimvihar, Raipur, Madhya Pradesh	1800
120	Prism Cement	Maihar, Satna, Madhya Pradesh	2000

Thermal power plants (coal-based): location and capacity

Sl no.	Location	Capacity (MW)
121	Anpara, Uttar Pradesh	1630
122	Badarpur, Delhi	420
123	Bhatinda GNDT, Punjab	440
124	Bhusawal, Maharashtra	420
125	Bokaro A & B, Bihar	630
126	Chandrapur STPS, Maharashtra	1840
127	Chandrapura, Bihar	620
128	Dadri, Uttar Pradesh	840
129	Farakkaha STPS, West Bengal	1600
130	Gandhinagar, Gujarat	660
131	Khalgaon, Bihar	840
132	Khaparkheda, Maharashtra	420
133	Kolaghat, West Bengal	1260
134	Koradi, Maharashtra	880
135	Korba STPS, Madhya Pradesh	2100
136	Korba West, Madhya Pradesh	840
137	Kota, Rajasthan	850
138	Kothagudem, Andhra Pradesh	430
139	Mettur, Tamil Nadu	840
140	Nasik, Maharashtra	910
141	Neyveli, Tamil Nadu	1770
142	Obra, Uttar Pradesh	1000
143	Panipat, Haryana	750
144	Parli, Maharashtra	630
145	Patratu, Bihar	430
146	Raichur, Karnataka	650
147	Ramagundam, Andhra Pradesh	2100
148	Rihand, Uttar Pradesh	2000
149	Ropar, Punjab	1050
150	Sanjay Gandhi, Madhya Pradesh	630
151	Santhaldih, Bihar	480
152	Satpura Sarni, Madhya Pradesh	830
153	Singrauli STPS, Uttar Pradesh	1000

Continued...

Sl no.	Location	Capacity (MW)
154	Talcher, Orissa	1220
155	Trombay, Maharashtra	1150
156	Tuticorin, Tamil Nadu	1050
157	Ukai, Gujarat	850
158	Unchahar, Uttar Pradesh	630
159	Vijaywada, Andhra Pradesh	1260
160	Vindhyachal, Madhya Pradesh	1760
161	Wanakbori, Gujarat	1260
162	Cuddapah, Andhra Pradesh	420
163	North Madras, Tamil Nadu	630
164	Ib Valley, Orissa	420
165	Dahanu, Maharashtra	500

Location of iron and steel plants

Sl no.	Location
166	Jamshedpur
167	Bokaro A&B
168	Vishakhapatnam
169	Bhillai
170	Burnpur
171	Durgapur
172	Rourkela

Location of major coalfields

Sl no.	Location
173	Raniganj
174	Jharia
175	East Bokaro
176	West Bokaro
177	Ramgarh
178	South Karanpura
179	North Karanpura
180	Daltonganj
181	Hutar
182	Singrauli
183	Sohagpur
184	Korba
185	Ib river
186	Talcher
187	Pench-Kanhan
188	Wardha valley
189	Rajmahal
190	Godavari
191	Makum, Namchik-Namphuk

Location of lignite mine

Sl no.	Location
192	Padundaro, Gujarat
193	Mangrol, Rajasthan
194	Bhavnagar, Gujarat
195	Birsinghpur, Rajasthan
196	Neyveli, Tamil Nadu

Location of major coal trading ports

Sl no.	Location
197	Paradip
198	Haldia
199	Vishakhapatnam
200	Tuticorin

Compared with the domestic availability, the projected demand for coal reveals a large demand–supply mismatch. Unless domestic production is augmented, large quantities of coal would have to be imported, and a huge amount would be lost as foreign exchange outgo. Investment required for increasing domestic production to meet the Ninth Plan projections is estimated to be over 200 billion rupees. Major policy changes are needed to get the best returns from this investment. The following measures are important in this regard.

- Improve the productivity of coal mines particularly that of underground mines. The OMS (output per man-shift) is very low in India when compared with international standards (see below).
- Clear factors that cause delays in opening new mines, such as environmental clearance, labour problems, problems of land acquisition, and rehabilitation of oustees.
- Deregulate coal prices such that they reflect the relative availability, substitutability, and calorific values of competing fuels.
- Make necessary legislative changes to the existing legal framework to facilitate private sector participation in coal production and distribution.
- Create regulatory mechanisms such that coal mines are properly and systematically developed and exploited and different grades of coal are appropriately priced.
- Persuade end-users to adopt proper demand management measures to reduce the need for capacity addition.

Mining technology

In India, mining technology shifted rapidly in favour of opencast mining over the last two decades. The increase in overall coal production over the period has mainly come from increased production from opencast mines. The Ninth Plan envisaged that 75% of the total projected production would come from opencast mines and the rest from underground mines.

In spite of substantial investments, the productivity of underground mines has not improved much due to difficult mining conditions, low levels of skill, and a large workforce. Immediate action, therefore, needs to be initiated to develop underground mines, which have a large potential for meeting the future demands, in view of their long gestation periods.

During extraction of coal through opencast mining, overburden and extraneous matter are mixed with the coal. Thus, with increase in opencast mining, the quality of coal has been found to deteriorate. To counter this problem, surface miners have been used in some mines of Ib Valley coalfield and they have been successful in extracting coal with a minimum level of extraneous matter. Surface miners extract slices of coal in 15–23 cm thick layers, which facilitates the segregation of layers that do not contain shale.

Productivity or overall OMS has improved during the last decade for the CIL and the SCCL (Singareni Collieries Company Limited) group of companies. The overall productivity is 2.0 for the CIL and 1.3 for the SCCL. While the OMS for opencast mining has improved, the OMS for underground mining has either declined or stagnated (Table 1.14). In 1994, the US had an average of 37.5 tonnes per man-shift and the figure in Germany's Hambach lignite mine was 43 tonnes per man-shift. Thus, there is a large scope for improving productivity in Indian mines.

Movement of coal

Since most of the coal production is restricted to the eastern and south-eastern belt of the country and core consumers such as power and steel plants are often distant from the coalfields, transportation of coal to the consumers is a major consideration. The railways is the main mode of transportation followed by captive systems such as MGR (merry-go-rounds). Road transport, conveyors, and aerial ropeways are also used. About six per cent of India's domestic coal transport is seaborne. Coastal shipment is used for supplying coal to consumers in South India.

The freight of coal on the Indian railways is among the highest in the world. This is because it cross-subsidizes the freight of foodgrains, fertilizer, and passenger fare.

India has 11 major ports, which are managed by the Port Trust of India under the jurisdiction of the central government. Important ports on the eastern coast, namely Haldia, Paradip, and Vishakapatnam, as well as several minor and intermediate ports (most of them on the western coast) receive coal imports. Around 11 MT of coal is carried by rail over relatively short distances to these ports each year, to be shipped to the southern ports of Chennai and Tuticorin. Coal imports are also received at these ports.

The government recently allowed private sector participation in the development and augmentation of port facilities.

Reforms in the coal sector

Given the importance of coal and lignite resources in India's overall energy strategy and the urgent need to develop these resources, the Planning Commission constituted a Committee on Integrated Coal Policy, which submitted its report in May 1996. The major recommendations included adoption of coal conservation measures; augmentation of domestic coal production by involving the private sector, integrating the exploratory efforts for coal and lignite, deregulating of coal prices, creating a regulatory body to look into price disputes, etc.; setting up more pithead coal- or lignite-based thermal power stations; augmentation of the railways and port infrastructure facilities; and amending/modifying various acts to facilitate private sector participation and expedite project clearance procedures. Deregulation of prices and distribution of all grades of coal and coal products are the only recommendations implemented so far by the government. Other recommendations, reported to be under active consideration of the government, are given below.

- Permission to any Indian company to mine coal without the restriction of captive consumption.
- Establishment of a regulatory body to perform an appellate function to resolve any price disputes between producers and consumers.
- Setting up an independent body to monitor the detailed and regional exploration of coal and lignite resources in the country.
- Allocation of new blocks on the basis of a competitive bidding process in which Indian companies including national coal companies may participate.

Implementation of some of these recommendations would necessitate amendments to various statutes governing coal mining in the country.

Coal imports

Coal can be freely imported by consumers based on requirements and commercial judgements under the open general licence. Coking coal is imported by SAIL (Steel Authority of India Limited) and other steel manufacturers to bridge the gap between requirements and the indigenous availability and also to improve the quality of the overall blend. With the lowering of import duty and the increase in price of domestic coal consequent to deregulation of indigenous coal prices, a number of coal-based power plants and cement plants have also started importing non-coking coal on consideration of transportation logistics and against export entitlements. Imports of coking and non-coking coal are shown in Table 1.12. Non-coking coal imports rose from 4.53 MT in 1996/97 to 6.56 MT in 1997/98. It is possible that imports of non-coking coal during 1998/99 were even higher than the officially stated figures.

At a basic customs duty of 15%, imports of coal were favourable especially near the ports. Imports of non-coking coal increased since the decontrol of prices of higher grades of coal in March 1996 and of all grades from April 2000. To protect the domestic coal market, the basic import duty on coal was increased to 25% in May 2000. Non-coking coal imports also attract a 10% surcharge on the basic duty and a special additional duty of 4%. This is expected to make imports less remunerative and give an edge to the Indian coal producer over the producers overseas. The cement plants located near the coastal regions and the sponge iron plants (direct reduction process using higher grade non-coking coal) are expected to be most affected by this hike as they account for the bulk of hard coal imports.

Captive coal mining

After nationalization of the coal mines in 1972/73, the development of coal was confined to the public sector. But in the early 1990s, the government decided to allow private sector participation in the power sector to augment thermal power generation and to create additional thermal power capacity. The Coal Mines (Nationalization) Act, 1973 was amended on 9 June 1993 to allow captive consumption of coal for generation of power to meet the anticipated increase in demand of private power producers. Later, production of cement and washing of coal for captive use were added to the list.

As a result of the notification, 105 captive mining blocks with an estimated reserve of 27 563 MT were identified in the command area of the CIL. Though several public and private sectors parties were offered captive coal blocks for consumption for power generation, it failed to attract private investors as the blocks offered were of poor quality.

In April 2000, a bill proposing further amendment to the Coal Mines (Nationalization) Act, 1973 was prepared to open up coal mining to private companies. If passed, the new law will provide free mining for all, with certain conditions on location and the minimum size of the mines so that coordinated and scientific development can take place.

Pricing reforms

The administered pricing set-up was last revised on 17 June 1994. The price notification was subsequently amended in December 1995 to enhance the differential among run of mine, steam, and slack coal; in January 1996 to include loading and transportation charges in some cases; and in April 1996 to take into account the additional prices for coal produced from Ramagundam OCP (opencast project) (SCCL) and Rajmahal OCP (eastern coalfields Ltd). Prices of coking coal and superior grades (A, B, C) of non-coking coal were deregulated vide notification dated 22 March 1996 and the prices were revised by the CIL with effect from 31 March 1996. Subsequently, the government also decided to deregulate the prices of soft coke, hard coke, and D grade non-coking coal with effect from 12 March 1997. Further, the CIL and the SCCL were allowed to fix prices of E, F, and G grades of non-coking coal once every six months based on the formula proposed by the Bureau of Industrial Costs and Prices in its 1987 report. The price of coal produced by the CIL and the SCCL entails royalty, stowing excise duty, and a four per cent central sales tax.

On 1 April 2000, the pricing of coal became fully deregulated vide the Colliery Control Order, 2000. This order supersedes the Colliery Control Order, 1945 of the Essential Commodities Act, 1955 under which the central government was empowered to fix the prices of coal by grade and colliery.

Since deregulation, the price of coal with advantageous geographic location (e.g. Rajmahal) is being pegged at a higher rate than that facing competition (e.g. Talcher in Mahanadi Coalfields) from imported coal or other fuels (Table 1.28).

Coal beneficiation

Coking coal reserves in the country are limited and only two to three per cent of the total coal reserves fall into the prime coking category. Most of the coking coal is found in Bihar. The coal in Jharia has the highest coking property even though the ash content is inherently high at 21%. After suitable beneficiation, this coal, referred to as prime coking coal, can be used to produce coke of the quality required by steel plants. Coking coal in other coalfields can yield suitable coke only when blended with prime coking coal and it is termed medium coking coal.

Most of the coking coal washing plants in India are old and have low unit capacity. Of the 20 washeries currently in operation, only one has an annual output of over 1 MT of washed coking coal and three have individual outputs of less than 300 000 tonnes a year. In addition, capacity utilization is typically in the order of 50%–65% and is expected to decline to about 48% by the end of the Ninth Plan. The details on raw coal feed and clean coal production by washery are provided in Table 1.18. Two of the washeries, Kargali and Giddi, have been converted to wash non-coking coal. The CIL has been having problems in maintaining its contractual obligations relating to a 17% maximum ash content in the coking coal supplied to SAIL as specified in the Altekar Committee in 1994/95 (Planning Commission 1996). Due to high ash content in the coal supplied to the steel industry (greater than 17%), the import dependency for coking coal is steadily increasing.

A major part of non-coking coal in India occurs in thick interbanded seams and is of inferior quality. Due to the poor quality of non-coking coal received by power stations, fly ash disposal becomes a critical problem. However, the MoEF (Ministry of Environment and Forests) has made it mandatory to supply clean coal (34% ash content) to all power stations located beyond 1000 km from the coalfields and to those located in critically-polluted, sensitive, and urban areas with effect from 1 June 2001. Currently, about 37% (100 MT) of non-coking coal is transported to power plants located beyond 1000 km from the coalfields. Furthermore, under the current proposal, there would be a phased introduction of maximum 34% ash in power station feed between 2000 and 2004 with all new generating capacity constructed after June 2000 designed to use this fuel.

Despite having long-term targets for the construction of about 60 MT annual washing capacity for non-coking coal, the construction of washing plants has not kept pace with the increasing coal mining capacity. As a result, large quantities of raw coal are being transported to power stations placing a severe constraint on the country's bulk freight services' capacity.

The CIL has not set up any washery of its own, other than on BOO (build-own-operate) or BOOT (build-own-operate-transfer) basis, due to the large costs and gestation period involved. In view of this, the Coal Mines (Nationalization) Act, 1973 was amended and about 20 MT of capacity is under construction/planning in the private sector. The Government of Andhra Pradesh also selected this route for providing washed coal from the SCCL's mines with a call for BOO tenders for the construction of three 8000-tonnes-per-day washeries at Manguru, Rudrampur, and Yellandu. The progress, however, has been very slow.

Legislative framework

Coal exploration and mining in India is governed by the Mines Act, 1952; the Mines and Minerals (Regulation and Development) Act, 1957; the Coal Mines Regulation Act, 1957; the Coal Mines (Nationalization) Act, 1973; the Forest Conservation Act, 1980; and the Environment Protection Act, 1986. Opening of new mines and subsequent operations require statutory permission from the Department of Coal, the Director General of Mine Safety, the MoEF, the State Pollution Control Board, and the respective state governments.

A mining lease that allows for the development and exploitation of coal needs to be obtained before undertaking any mining operations. It is granted by the state government after it is approved by the Government of India under the Mines and Minerals (Regulations and Development) Act, 1957. Mining leases are granted for 30 years initially and are renewed for a period of 20 years with the government's approval. The lease is ordinarily subject to a ceiling of 10 square kilometres of area.

The legal and regulatory framework needs to reflect the policy of the government. Coal mining projects in India are required to address environmental and social issues. The Environment Action Plan, the Rehabilitation Action Plan, and the Indigenous People's Development Plan are now an integral part of any coal project. The revision of the legislative framework, however, has not kept pace with the evolving policy that aims at reducing the role of the government as a developer of resources. The legislative provisions, therefore, need to operate within a framework that is beneficial for the investors and provides accessibility to latest technologies in the coal industry.

Policy recommendations

In a liberalized economy, competition is the guiding factor for reliable product and services. Currently, 98% of coal is produced from national coal companies, of which 88% is produced by the CIL and 10% by the SCCL. As such, there is no competition in the industry.

Private sector participation needs to be facilitated so as to bring about competition among the coal producers and prevent cartelization. The necessary legislative changes have to be made to facilitate private sector participation in coal production and distribution. Even though some changes have been initiated, administrative procedures have to be further streamlined to expedite the necessary clearances and the required legislative changes (Sengupta 1999).

Delays in new projects due to paucity of funds can be reduced by forming joint ventures between the public and private sector coal companies and the concerned state government. This will not only help resolve procedural difficulties in project implementation but also overcome problems related to land acquisition, rehabilitation of people ousted from the land, and forest clearances. Joint ventures will lead to consumer satisfaction with regard to quality and assured supply of coal economically. Some of the independent power producers, for instance, may have the resources to take up mining but they may not have the expertise, in which case they may like to enter into equity participation with the existing coal companies. Similarly, public sector utilities, such as the National Thermal Power Corporation, may like to enter into equity participation with the coal producers like the SCCL and the CIL for their proposed pithead power stations. In addition, SAIL and other steel producers in the private sector may enter into joint ventures with the CIL for developing new coking coal mines instead of relying on imports for their future requirements.

Due to the pre-liberalization structure of the coal industry, with a high degree of concentration of reserves and assets with the nationalized producers, the infrastructure bottlenecks, and the statutory and legal barriers, the Indian coal sector may not operate under conditions of competitive price-setting over the medium term. Moreover, the transition from a monopoly to a competitive system requires balancing of interests of the various participants in the market. This implies that an independent regulatory body will be indispensable.

Conclusion

With the opening up of the economy and recent reforms, the market is likely to be driven more by the availability of alternative fuel choices and the competitiveness of fuel prices. Further, sectoral reforms and policies cannot be successful in isolation. Therefore, reforms in the coal sector must be examined within the overall context of an integrated energy policy for the country.

The Indian coal industry must look at the international scene for a wider perspective and cooperation and not just for importing technology. The difficult mining conditions, culture of workforce, and capability of absorbing scientific technology demand that we develop our indigenous methods for attaining sustainable development.

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Table 1.01 Coal resources of states (million tonnes): 1 January 2000

State	*Proved*	*Indicated*	*Inferred*	*Total*
Andhra Pradesh	7,346	3,312	2,929	13,587
Arunachal Pradesh	31	11	48	90
Assam	259	27	34	320
Bihar	34,794	28,692	5,642	69,128
Madhya Pradesh	13,010	22,148	8,334	43,493
Maharashtra	4,149	1,323	1,605	7,077
Meghalaya	118	41	301	459
Nagaland	3	1	15	20
Orissa	11,140	22,755	16,554	50,449
Uttar Pradesh	766	296	0	1,062
West Bengal	10,779	10,894	4,236	25,909
Total	82,396	89,501	39,697	211,594

Source
MoC. 2000. ***Annual Report 1999/2000.*** New Delhi: Ministry of Coal.

For more details, please see TEDDY ONLINE+ [Section: Coal (reserves)]

Table 1.02 Coal reserves by category (million tonnes): 1 January 2000

Types of coal	*Proved*	*Indicated*	*Inferred*	*Total*
Coking				
Prime coking	4,614	699	–	5,313
Medium coking	11,267	11,133	1,106	23,506
Blendable/semi-coking	482	904	222	1,608
Sub-total	16,364	12,735	1,328	30,427
Non-coking[a]	66,032	76,765	38,369	181,167
Total	82,396	89,501	39,697	211,594

[a] including coals of the north-eastern region

Source
MoC. 2000. ***Annual Report 1999/2000.*** New Delhi: Ministry of Coal.

For more details, please see TEDDY ONLINE+ [Section: Coal (reserves)]

Table 1.03 Lignite reserves of states and union territories (million tonnes): 1998/99

State / Union Territory	*Geological reserves*
Tamil Nadu and Pondicherry	
Neyveli	3,300
Bahur	575
Jayamkondacholapuram	1,167
Mannargudi	19,500
East of Veeranam	1,422
Kudikadu	133
Micheal Patti	23
Meensuruti	458
Kulanchavadi	175
Rajasthan	1,828
Gujarat	1,505
Jammu and Kashmir	128
Kerala	108
Total	30,322

Source
MoC. 2000. ***Annual Report 1999/2000.*** New Delhi: Ministry of Coal.

For more details, please see TEDDY ONLINE+ [Section: Coal (reserves)]

Table 1.04 All-India production of coal, lignite, and other derivatives (million tonnes): 1975/76 to 1999/2000

Items	*1975/76*	*1980/81*	*1985/96*	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/00*
Coking coal	27.4	31.7	35.2	44.9	45.80	45.21	44.66	41.97	39.91	40.50	43.80	39.2	33.0
Non-coking coal	72.3	82.3	119.1	169.0	187.00	196.80	204.02	215.80	233.50	245.50	253.33	253.1	267.1
Total coal[a]	99.7	114.0	154.3	213.9	232.80	242.00	248.68	257.77	273.42	286.10	297.20	292.3	300.1
Lignite	3.0	5.1	8.0	14.1	15.99	16.62	18.10	19.31	22.15	22.60	23.10	23.4	22.1
Total coal and lignite	102.7	119.1	162.3	225.7	245.40	255.11	266.78	277.08	295.56	308.70	320.20	315.7	322.2
Soft coke	2.7	2.3	1.7	0.9	0.73	0.48	0.43	0.25	0.17	0.10	–	–	–
Beehive hard coke	0.8	0.6	0.3	0.1	0.17	0.13	0.12	0.08	0.06	0.10	0.10	–	–
By-product hard coke	0.6	0.4	0.3	10.2	10.48	10.60	10.58	10.93	10.86	11.00	10.60	10.8	11.4
Washed coal	11.4	11.6	10.9	11.2	12.50	12.80	12.14	11.75	11.92	10.90	10.00	9.7	9.1
Middlings	3.9	4.3	5.1	5.6	6.07	6.46	6.64	6.30	6.80	6.80	7.60	7.2	6.2
Total exports	0.4	0.1	0.2	0.1	0.11	0.13	0.10	0.12	0.09	0.10	0.10	–	–
Total imports	–	0.6	2.0	4.9	5.92	6.70	7.10	8.30	8.90	9.50	9.50	–	–

[a] includes Meghalaya figures for the unorganized sector

Source

CCO. *Coal Directory of India* (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

For more details, please see TEDDY ONLINE+ Section: [Coal (general, production, and despatch)]

Table 1.05 Coal production of various states (million tonnes): 1975/76 to 1999/2000

State	*1975/76*	*1980/81*	*1985/86*	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/00*
Andhra Pradesh	7.4	10.1	15.7	17.7	20.6	22.5	25.3	25.7	25.0	28.7	28.9	27.3	29.6
Assam	0.6	0.6	0.9	0.7	1.0	1.1	1.2[a]	1.2[a]	0.8	0.8	0.7	0.6	0.6
Bihar	41.8	46.6	54.3	67.3	69.0	71.1	73.3	73.3	74.6	77.7	81.3	76.2	76.9
Madhya Pradesh	20.4	25.9	42.6	65.2	69.4	70.7	72.9	74.9	79.8	83.3	84.8	84.9	87.9
Maharashtra	3.7	5.8	11.6	16.9	18.9	19.7	20.5	21.1	22.8	24.9	26.2	25.3	27.7
Meghalaya	–	–	–	2.2	3.5	3.5	2.5	3.3	3.3[b]	–	–	–	–
Orissa	2.2	3.2	6.0	16.2	20.7	23.1	24.3	27.3	32.7	37.4	42.2	43.5	43.6
Uttar Pradesh	–	1.8	3.9	10.5	11.5	12.2	12.1	13.8	14.8	15.4	15.8	15.6	16.2
West Bengal	23.7	20.0	19.4	17.2	18.2	18.1	16.6	17.2	17.9	18.0	17.4	18.8	17.6
All-India	99.8	114.0	154.4	213.9	232.8	242.0	248.7	257.8	273.5	286.1	297.2	292.3	300.1

[a] includes Arunachal Pradesh and Meghalaya under the north-eastern coalfields

[b] figures for the unorganized sector

Source

CCO. *Coal Directory of India* (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

For more details, please see TEDDY ONLINE + [Section: Coal (general, production, and despatch)]

Table 1.06 Coal despatches of various states (million tonnes): 1975/76 to 1999/2000

State	*1975/76*	*1980/81*	*1985/86*	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/00*
Andhra Pradesh	7.0	10.1	15.4	24.6	20.0	21.7	24.6	24.0	24.9	28.8	29.0	26.7	29.8
Assam	0.6	0.1	0.8	0.9	1.0	0.9	0.8[a]	0.8[a]	1.0[a]	0.8	0.6	0.7	0.8
Bihar	33.1	39.1	53.7	60.8	63.1	69.4	72.6	73.2	72.7	76.0	77.1	75.5	77.2
Madhya Pradesh	19.5	24.6	42.0	62.8	68.0	69.7	72.1	73.1	78.6	83.7	86.5	83.8	87.1
Maharashtra	3.4	5.7	11.7	17.4	18.9	19.1	19.8	21.2	24.3	24.7	25.0	24.3	28.4
Meghalaya	–	–	–	2.2	3.5	3.5	2.5	3.3	3.3[b]	–	–	–	–
Orissa	2.0	2.8	5.3	16.0	19.6	21.9	24.0	26.9	34.4	37.2	43.3	41.8	42.1
Uttar Pradesh	–	1.6	3.6	10.2	11.4	11.6	12.9	13.7	14.9	15.7	15.6	14.8	16.7
West Bengal	21.2	17.3	18.5	15.7	17.1	16.3	15.8	16.2	16.6	16.7	16.8	17.2	18.3
All-India	86.8	101.3	151.0	210.6	222.6	234.1	245.1	252.4	270.7	283.7	293.9	284.7	300.4

[a] includes Arunachal Pradesh and Meghalaya under the north-eastern coalfields

[b] figures for the unorganized sector

Source

CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

For more details, please see TEDDY ONLINE + [Section: Coal (general, production, and despatch)]

Table 1.07 Coal pithead stock of various states (million tonnes): 1975/76 to 1999/2000

State	*1975/76*	*1980/81*	*1985/86*	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/00*
Andhra Pradesh	0.5	0.5	0.6	0.7	0.7	0.9	0.9	2.1	2.5	1.9	1.4	1.7	1.2
Assam	–	–	0.2	0.3	0.1	0.4	0.8	1.2	0.9	0.8	0.9	0.8	0.6
Bihar	6.8	11.1	16.5	24.7	29.4	29.2	28.5	22.4	22.9	20.8	23.4	18.1	9.2
Madhya Pradesh	1.7	3.3	6.1	7.8	8.4	8.7	8.9	10.0	10.6	9.5	7.1	7.8	8.0
Maharashtra	0.2	0.2	0.8	2.4	2.1	2.6	3.0	2.7	1.0	1.1	2.0	2.8	2.1
Meghalaya	–	–	–	–	–	–	–	–	–	–	–	–	–
Orissa	0.4	0.5	2.1	3.1	4.1	4.6	4.8	5.2	3.4	3.5	2.3	4.0	5.4
Uttar Pradesh	0	0.1	0.2	0.7	0.8	1.5	0.6	0.8	0.7	0.4	0.4	1.3	0.8
West Bengal	2.2	2.7	2.5	2.9	2.9	3.5	3.1	3.2	3.7	4.1	3.9	3.7	1.4
All-India	11.8	18.4	29.0	42.6	48.5	51.4	50.6	47.6	45.7	42.0	41.5	40.1	28.7

Source

CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

For more details, please see TEDDY ONLINE + [Section: Coal (general, production, and despatch)]

Table 1.08 Coal production of various companies (million tonnes): 1993/94 to 1998/99

Company	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*
Coal India Ltd						
Eastern Coalfields Ltd	22.61	24.85	27.80	29.65	27.44	27.16
Bharat Coking Coal Ltd	29.04	28.75	27.81	27.14	30.92	27.18
Central Coalfields Ltd	33.51	31.21	30.76	32.21	33.10	32.18
South-Eastern Coalfields Ltd	47.53	50.00	53.17	55.30	56.63	57.56
Mahanadi Coalfields Ltd	24.29	27.33	32.70	37.37	42.16	43.51
Western Coalfields Ltd	26.50	27.24	29.01	31.23	32.51	31.74
Northern Coalfields Ltd	31.41	32.50	35.20	37.01	37.56	36.52
North-Eastern Coalfields	1.20	1.19	0.82	0.75	0.69	0.64
Total	216.10	223.07	237.28	250.65	261.01	256.49
Singareni Collieries Company Ltd	25.28	25.65	26.77	28.73	28.94	27.33
Jammu and Kashmir Minerals Ltd	0.02	0.02	0.02	0.02	0.01	0.01
Damodar Valley Corporation	0.07	0.29	0.23	0.29	0.36	0.37
Bengal Emta Coal Mines Ltd	–	–	–	–	0.71	1.80
Bihar State Mineral Development Corporation Ltd	–	–	–	0.26	0.20	0.19
Indian Iron and Steel Company Ltd	0.72	1.04	0.99	0.86	0.72	0.84
Tata Iron and Steel Company Ltd	3.96	4.16	4.90	5.30	5.23	5.22

Source

CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.09 Coal despatches of various companies (million tonnes): 1993/94 to 1998/99

Company	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*
Coal India Ltd						
Eastern Coalfields Ltd	22.19	24.22	25.81	28.04	26.64	25.54
Bharat Coking Coal Ltd	28.54	28.34	26.55	26.75	27.57	26.83
Central Coalfields Ltd	33.02	31.18	30.84	31.19	32.49	31.98
South-Eastern Coalfields Ltd	46.91	47.81	52.27	56.12	58.33	56.93
Mahanadi Coalfields Ltd	24.00	26.93	34.36	37.22	43.40	41.76
Western Coalfields Ltd	25.52	27.26	30.37	30.91	31.35	30.44
Northern Coalfields Ltd	32.37	32.92	35.07	37.09	37.47	35.46
North-Eastern Coalfields	0.75	0.83	1.03	0.83	0.57	0.70
Total	213.30	219.49	236.29	248.15	257.82	249.63
Singareni Collieries Company Ltd	24.60	25.04	24.87	28.82	29.02	26.71
Jammu and Kashmir Minerals Ltd	0.02	0.02	0.02	0.02	0.01	0.01
Damodar Valley Corporation	0.07	0.27	0.23	0.29	0.36	0.33
Bengal Emta Coal Mines Ltd	–	–	–	–	0.69	1.78
Bihar State Mineral Development Corporation Ltd	–	–	–	0.26	0.19	0.20
Indian Iron and Steel Company Ltd	0.68	1.03	1.00	0.87	0.73	0.81
Tata Iron and Steel Company Ltd	3.94	4.28	4.91	5.29	5.20	5.21

Source

CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.10 Coal pithead stock of various companies (million tonnes): 1993/94 to 1998/99

Company	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*
Coal India Ltd						
Eastern Coalfields Ltd	6.55	6.17	7.21	5.19	5.09	5.90
Bharat Coking Coal Ltd	13.29	8.02	8.56	8.26	10.95	4.76
Central Coalfields Ltd	11.51	11.13	10.57	11.21	11.03	10.91
South-Eastern Coalfields Ltd	7.07	8.80	9.22	7.89	6.01	6.27
Mahanadi Coalfields Ltd	4.82	5.15	3.40	3.48	2.29	4.00
Western Coalfields Ltd	3.52	3.15	1.44	1.43	2.29	3.31
Northern Coalfields Ltd	1.91	1.49	1.61	1.62	1.27	2.29
North-Eastern Coalfields	0.82	1.17	0.87	0.83	0.93	0.84
Total	49.48	45.07	42.87	39.9	39.84	38.24
Singareni Collieries Company Ltd	0.95	2.09	2.52	1.89	1.38	1.67
Jammu and Kashmir Minerals Ltd	0.01	0.01	–	–	–	–
Damodar Valley Corporation	–	0.02	–	–	–	0.04
Bengal Emta Coal Mines Ltd	–	–	–	–	0.02	0.03
Bihar State Mineral Development Corporation Ltd	–	–	–	0.01	0.01	0.03
Indian Iron and Steel Company Ltd	0.27	0.23	0.21	0.18	0.17	0.03
Tata Iron and Steel Company Ltd	0.05	0.08	0.05	0.04	0.04	0.04

Source

CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.11 Production (million tonnes) of coking coal and non-coking coal by companies and fields: 1994/95 to 1999/2000

State / Field / Company	1994/95		1995/96		1996/97		1997/98		1998/99		1999/00	
	Coking	*Non-coking*	*Coking*	*Non-coking*	*Coking*	*Non-coking*	*Coking*	*Non-coking*	*Coking*	*Non-coking*	*Coking*	*Non-coking*
West Bengal												
Bharat Coking Coal Ltd	0.18	0.57	0.17	0.51	0.13	0.43	0.13	0.59	0.32	0.42	–	–
Eastern Coalfields Ltd	0.14	15.82	0.13	16.68	0.15	16.95	0.09	15.73	0.08	16.05	–	–
Indian Iron and Steel Company Ltd	0.02	0.51	0.01	0.42	0.03	0.30	0.05	0.16	0.01	0.29	–	–
Bengal Emta Coal Mines Ltd	–	–	–	–	–	–	–	0.71	–	1.79	–	–
Total	0.34	16.90	0.31	17.61	0.31	17.69	0.27	17.18	0.22	18.55	–	–
Bihar												
Bharat Coking Coal Ltd	22.30	5.69	21.55	5.58	21.27	5.31	24.19	6.01	21.57	5.06	–	–
Eastern Coalfields Ltd	0.29	8.60	0.24	10.76	0.22	12.33	0.21	11.42	0.21	10.83	–	–
Central Coalfields Ltd	13.38	18.11	11.45	19.31	11.75	20.43	12.23	20.87	10.03	22.15	–	–
Damodar Valley Corporation	–	0.29	–	0.23	–	0.29	–	0.36	0.37	–	–	–
Bihar State Mineral Development Corporation Ltd	–	–	–	–	–	0.26	–	0.20	–	0.19	–	–
Indian Iron and Steel Company Ltd	0.51	–	0.56	–	0.52	–	0.51	–	0.53	0.01	–	–
Tata Iron and Steel Company Ltd	4.16	–	4.90	–	5.30	–	5.23	–	5.14	0.08	–	–
Total	40.64	32.69	38.69	35.87	39.05	38.63	42.36	38.85	37.84	38.32	–	–
Outlying fields												
Northern Coalfields Ltd	–	32.50	–	35.20	–	37.01	–	37.56	–	36.52	–	38.43
South Eastern Coalfields Ltd	0.13	49.87	0.16	53.01	0.48	54.83	0.47	56.16	0.46	57.10	–	–
Mahanadi Coalfields Ltd	–	27.33	–	32.70	–	37.37	–	42.16	–	43.51	–	43.55
Western Coalfields Ltd	0.86	26.39	0.75	28.25	0.70	30.52	0.74	31.78	0.65	31.08	–	–
North Eastern Coalfields	–	1.19	–	0.82	–	0.75	–	0.69	–	0.64	–	0.57
Singareni Collieries Company Ltd	–	25.65	–	26.77	–	28.73	–	28.94	–	27.33	–	27.56
Jammu and Kashmir Minerals Ltd	–	0.02	–	0.02	–	0.02	–	0.01	–	0.01	–	0.03
Total	0.99	162.95	0.91	176.78	1.18	189.23	1.21	197.30	1.11	196.19	–	–

Public												
Coal India Ltd	37.28	186.07	34.45	202.82	34.69	215.93	38.06	252.62	34.04	251.19	–	–
Singareni Collieries Company Ltd	–	25.65	–	26.77	–	28.73	–	28.94	–	27.33	–	27.56
Jammu and Kashmir Minerals Ltd	–	0.02	–	0.02	–	0.02	–	0.01	0.01	–	–	–
Damodar Valley Corporation	–	0.29	–	0.23	–	0.29	–	0.36	0.37	–	–	–
Bengal Emta Coal Mines Ltd	–	–	–	–	–	–	–	0.71	–	1.79	–	–
Bihar State Mineral Development Corporation Ltd	–	–	–	–	–	0.26	–	0.20	–	0.19	–	–
Indian Iron and Steel Company Ltd	0.53	0.51	0.57	0.42	0.55	0.30	0.56	0.16	0.53	0.01	–	–
Total	37.81	212.54	35.02	230.25	35.25	245.54	38.62	252.62	34.04	251.19	–	–
Private												
Tata Iron and Steel Company Ltd	4.16	–	4.90	–	5.30	–	5.23	0.71	5.14	0.08	–	–
All India	41.97	212.54	39.91	230.25	40.54	245.54	43.84	253.33	39.18	253.09	–	–

Source

CCO. 1999. ***Coal Directory of India 1998/99***. Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.12 Import of coking and non-coking coal (**million tonnes**): 1991/92 to 1998/99

Year	*Coking coal*	*Non-coking coal*	*Total*
1991/92	5.27	0.66	5.93
1992/93	6.32	0.42	6.74
1993/94	6.82	0.57	7.39
1994/95	10.15	1.24	11.39
1995/96	9.37	3.14	12.51
1996/97	9.78	4.53	14.31
1997/98	10.65	6.56	17.21
1998/99[a]	9.64	6.00	15.64

[a] provisional

Source

MoC. 1999. ***Annual Report* 1998/99.** New Delhi: Ministry of Coal.

Table 1.13 Allotted captive mining blocks: March 1997

Thermal power station / Company	*Captive block*	*Estimated coal reserves (million tonnes)*	*Estimated production potential (million tonnes a year*
Power sector			
RPG/CESC - Budge Budge	Sarisathali	60 (mineable)	3.0
RPG - Chandil	South Dhadhu	60 (mineable)	2.0
RPG - Dholpur	Mahan	75 (mineable)	2.5
KPC - Duburi	Utkal-A	200 (geological)	2.5
NDIL - Bhadravati	Lohara W Baranj(IIV) and Bander	286 (geological)	4.5
APSEB - Krishnapatnam I	Gopalprasad	240 (mineable)	10.8
APSEB - Vishakhapatnam II	West II		
TNEB	Gopalprasad W I	240 (mineable)	8.0
INDALCO - Hirakud	Talabira I	17 (geological)	0.5
DCL - Sagardighi	Chuperbhita	289 (geological)	5.0
ACC - Wadi	Lohara East	14 (mineable)	0.3
HOKI - Hospet	Utkal B 1(since withdrawn)	200 (geological)	2.0
WBSEB - Bandel and Santaldih	Tara East	40 (mineable)	1.2
Videocon - N. Chennai II	Utkal B 1	200 (geological)	5.0
Jindal Strips - Raigarh	Gare Pelma	100 (geological)	1.0
Iron and steel			
Jindal Strips Ltd	Gare block sub-block IV/I	–	–
Prakash Industries	Hasdev Avand	–	–
Birla Technical Service Ltd	Pakribarwadih	–	–
Steel Authority of India Ltd	Seetanala, Tasra, Parbatpur and Mahal	–	–
Monnet Ispat Ltd	Gare block sub-block IV/5	–	–
Cement			
ACC Ltd	Bisrar	–	–
J K Corporation Ltd	Gare-Palma IV/8	–	–

RPG - Reliance Power Goup; CESC - Calcutta Electric Supply Company; KPC - Karnataka Power Corporation; NDIL - Nippon Denro Ltd; APSEB - Andhra Pradesh State Electricity Board; TNEB - Tamil Nadu Electricity Board; INDALCO - Indian Aluminium Company Ltd; DCL - Development Consultant Ltd; ACC - Associated Cement Company Ltd; WBSEB - West Bengal State Electricity Board

Source

Data obtained from the Ministry of Coal, New Delhi (1998).

Table 1.14 OMS (Output per man-shift) in opencast and underground mining (tonnes), 1975/76 to 1999/2000

Companies	*1975/76*	*1980/81*	*1985/86*	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*[a]	*1999/00*[a]
Overall													
CIL	0.65	0.70	0.92	1.30	1.40	1.46	1.52	1.63	1.75	1.86	1.93	2.03	1.99
SCCL	0.69	0.70	0.92	0.96	0.98	1.04	1.05	1.08	1.23	1.19	1.31	1.31	1.31
Opencast													
CIL	0.90	1.50	2.24	3.31	3.70	3.80	4.00	4.35	4.73	5.12	5.07	5.52	5.29
SCCL	0	0	3.54	4.74	4.48	4.46	4.38	3.63	3.66	2.96	3.50	3.92	4.00
Underground													
CIL	0.60	0.50	0.53	0.53	0.53	0.55	0.55	0.56	0.56	0.57	0.57	0.59	0.60
SCCL	–	–	0.87	0.65	0.67	0.70	0.71	0.69	0.74	0.72	0.76	0.75	0.73

CIL - Coal India Ltd; SCCL - Singareni Collieries Company Ltd

[a] April-December

Note

The OMS of the SCCL is worked out on the CIL formula from 1987/88.

Source

MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table 1.15 Categorization of coal and coke

Class	*Grade*	*Properties*
Non-coking coal produced in all states other than Assam, Arunachal Pradesh, Meghalaya, and Nagaland	A	UHV (Useful heat value) greater than 6200 kcal/kg
	B	UHV 5600 6200 kcal/kg
	C	UHV 4940 5600 kcal/kg
	D	UHV 4200 4940 kcal/kg
	E	UHV 3360 4200 kcal/kg
	F	UHV 2400 3360 kcal/kg
	G	UHV 1300 2400 kcal/kg
Non-coking coal produced in the states of Arunachal Pradesh, Assam, Meghalaya, and Nagaland	Not graded	
Coking coal		
Steel	I	Ash content not exceeding 15%
Steel	II	Ash content greater than 15% but less than 18%
Washery	I	Ash content greater than 18% but less than 21%
Washery	II	Ash content greater than 21% but less than 24%
Washery	III	Ash content greater than 24% but less than 28%
Washery	IV	Ash content greater than 28% but less than 35%
Semi-coking and weakly coking coals		
Semi-coking	I	Ash plus moisture content not exceeding 19%
Semi-coking	II	Ash plus moisture content greater than 19% but not exceeding 24%
Long-flame coal produced in collieries in all the states excepting Assam, Arunachal Pradesh, Meghalaya, Nagaland, and the Singareni collieries in Andhra Pradesh	A	UHV greater than 6200 kcal/kg
	B	UHV greater than 5600 kcal/kg but not exceeding 6200 kcal/kg
	C	UHV greater than 4940 kcal/kg but not exceeding 5600 kcal/kg
	D	UHV greater than 4200 kcal/kg but not exceeding 4940 kcal/kg
Hard coke		
By-product	Premium	Ash content not exceeding 25%
By-product	Ordinary	Ash content greater than 25% but not exceeding 30%
Beehive	Premium	Ash content not exceeding 27%
Beehive	Superior	Ash content greater than 27% but not exceeding 31%
Beehive	Ordinary	Ash content greater than 31% but not exceeding 36%

Notes

1 Coking coals have been classified thus by the erstwhile Coal Board under the Coal Mines (Conservation, Safety, and Development) Act, 1952 (12 of 1952) (since repealed) or such coals as have been declared or may be declared as coking coal by the central government under the Colliery Control Order, 1945, or the Coal Mines (Conservation and Development) Act, 1974 (28 of 1974), and the rules made under both the aforesaid Acts.

2 Semi-coking coals and weakly-coking coals are classified as 'blendable coals' by the erstwhile Coal Board under the Coal Mines (Conservation, Safety, and Development) Act, 1952 (12 of 1952) (since repealed), or as may be declared as 'semi-coking' or 'weakly coking' coals by the central government under the Colliery Control Order, 1945, or the Coal Mines (Conservation and Development) Act 1974 (28 of 1974), and the rules made under both the aforesaid Acts.

3 Coals other than coking, semi-coking, or weakly-coking coals are non-coking coals.

4 UHV is defined by the formula: UHV in kcal/kg = (8900 - 138 x [percentage of ash content + percentage of moisture content]). In the case of coal having moisture less than 2% and volatile content less than 19%, the UHV shall be the value arrived as above, reduced by 150 kcal/kg for each 1% reduction in volatile content below 19% fraction pro-rata. Both moisture and ash shall be determined after equilibrating at 60% relative humidity and 40°C temperature as per relevant clauses of the Indian Standard Specification No. IS:1350-1959.

5 Ash percentage of coking coals and hard coke shall be determined after air-drying as per IS:1350-1959. If the moisture so determined is more than 2%, the determination shall be after equilibrating at 60% relative humidity at 40°C as per IS:1350-1959.

6 Long-flame coals shall be defined by the parameters as laid down in Table II of the Indian Standard Specification No. IS:770-1964, 'General classification of coals (Revised)'. The volatile matter (on unit coal basis) present in these coals exceeds 32%.

7 The above classification shall not apply to coals other than bituminous or sub-bituminous coals as specified under the Indian Standard Specification No. IS:77-1964.

Source

MoC. 1995. **The Gazette of India.** Extraordinary, Part II, Section 3, Sub-section (ii), No. 718. pp. 3-4. New Delhi: Ministry of Coal. 5 pp.

Table 1.16 Comparison of GCV (gross calorific value) and UHV (useful heat value) for non-coking coal (with six per cent moisture content)

Grade	*UHV (kcal/kg)*		*Ash (%)*		*GCV (kcal/kg)*	
	From	*To*	*From*	*To*	*From*	*To*
A	–	>6200	–	<13.56	–	>6406
B	5600	6200	13.56	17.91	5997	6406
C	4940	5600	17.91	22.69	5447	5997
D	4200	4940	22.69	28.06	5042	5447
E	3360	4200	28.06	34.14	4469	5042
F	2400	3360	34.14	41.10	3814	4469
G	1300	2400	41.1	49.07	3064	3814

Source

TERI. 1997. **Relative economics of fuels in power generation.** TERI Report. New Delhi: Tata Energy Research Institute.

Table 1.17 Production from coal washeries (million tonnes): 1975/76 to 1999/2000

Feed and production	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1999/00*
Prime coking coal										
Raw coal feed	12.47	12.57	12.05	12.95	13.30	13.09	12.8	–	–	–
Clean coal production	6.44	6.78	6.54	6.69	6.88	6.76	5.9	4.5	–	–
Middling production	3.08	3.47	3.48	3.70	3.52	4.00	3.7	–	–	–
Medium coking coal										
Raw coal feed	8.03	9.24	10.44	9.74	9.44	9.91	9.4	–	–	–
Clean coal production	4.73	5.16	5.56	5.43	4.87	5.10	5.0	5.4	–	–
Middling production	2.46	2.60	2.98	2.91	2.81	2.80	3.1	–	–	–
Total										
Raw coal feed	20.50	21.81	22.49	22.69	22.74	23.00	22.2	22.0	21.1	12.0
Clean coal production	11.10	12.00	12.10	12.12	11.75	11.90	10.9	10.0	9.7	5.6
Middling production	5.60	6.07	6.46	6.61	6.33	6.80	6.8	7.5	7.2	4.4

Sources

1 CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

2 MoC. 1998. ***Annual Report 1997/98***. New Delhi: Ministry of Coal.

For more details, please see TEDDY ONLINE+ [Section: Coal (general, production, and despatch)]

Table 1.18 Raw coal feed (million tonnes) and clean coal production (million tonnes) of washeries: 1993/94 to 1998/99

Company/ Washeries	*Raw coal feed*						*Clean coal production*					
	1993/94	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*	*1998/99*
Bharat Coking Coal Ltd												
Dugda I	1.14	1.09	0.85	0.53	0.01	0.11	0.54	0.51	0.48	0.26	0	0.07
Dugda II	1.25	1.25	1.10	1.10	1.22	0.99	0.60	0.59	0.62	0.48	0.48	0.40
Bhojudih	1.51	1.61	1.49	1.45	1.49	1.50	0.98	1.01	0.98	0.86	0.83	0.80
Patherdih	0.93	1.01	1.02	0.98	0.81	0.73	0.52	0.62	0.65	0.55	0.34	0.27
Lodna	0.37	0.34	0.34	0.28	0.25	0.33	0.20	0.19	0.18	0.14	0.11	0.14
Sudamdih	0.85	1.02	0.94	0.90	0.84	0.88	0.34	0.47	0.42	0.39	0.33	0.32
Barora	0.32	0.33	0.32	0.34	0.36	0.32	0.12	0.13	0.15	0.14	0.14	0.11
Moonidih	1.05	1.07	0.99	0.98	1.03	0.92	0.51	0.55	0.50	0.49	0.51	0.44
Mohuda	0.36	0.34	0.35	0.37	0.37	0.35	0.26	0.24	0.24	0.24	0.25	0.22
Total	7.78	8.06	7.40	6.93	6.38	6.23	4.07	4.31	4.22	3.55	3.00	2.81
Central Coalfields Ltd												
Kargali	2.44	2.18	2.04	1.94	1.72	1.60	1.35	1.05	1.01	1.02	0.79	0.69
Kathara	1.83	1.76	1.73	1.55	1.62	1.71	0.82	0.78	0.72	0.61	0.55	0.55
Swang	0.99	0.99	0.97	0.81	0.71	0.79	0.70	0.60	0.61	0.46	0.41	0.43
Gidi	1.80	1.79	1.95	1.64	1.79	0.16	0.96	0.92	0.93	0.68	0.62	0.04
Rajrappa	1.71	1.70	2.18	2.42	2.13	2.13	0.97	0.90	1.23	1.39	1.01	0.98
Kedla	0	0	0	0.01	0.62	1.00	0	0	0	0	0.25	0.39
Total	8.77	8.42	8.87	8.37	8.59	7.39	4.80	4.24	4.50	4.15	3.63	3.08
Western Coalfields Ltd												
Nandan	0.61	0.68	0.69	0.65	0.68	0.66	0.37	0.39	0.42	0.41	0.39	0.35
Coal India Ltd												
Durgapur Steel Plant	17.16	17.16	16.96	15.95	15.65	14.28	9.24	8.94	9.14	8.11	7.02	6.24
Durgapur Steel Plant Washery	0.47	0.41	0.24	0.12	0.14	0.41	0.30	0.27	0.19	0.09	0.10	0.31
Durgapur Power Ltd												
Durgapur Power Limited Washery	0.01	0.01	0	0	0	0	0.01	0.01	0	0	0	0

Indian Iron and Steel Company												
Chasnala	1.16	1.11	1.00	0.85	1.03	1.14	0.59	0.58	0.54	0.50	0.58	0.63
Total	1.64	1.53	1.24	0.97	1.17	1.55	0.90	0.85	0.73	0.59	0.68	0.68
Public sector	18.80	18.69	18.20	16.92	16.85	15.83	10.13	9.79	9.87	8.70	7.70	7.20
Tata Iron and Steel Company												
West Bokaro I	0.61	0.51	0	0	0	1.87	0.34	0.29	0	0	0	0
West Bokaro II	1.90	1.78	1.72	1.82	1.87	1.94	0.72	0.67	0.62	0.66	0.69	0.77
West Bokaro III	0	0.43	1.81	2.13	2.07	1.43	0	0.16	0.63	0.75	0.74	0.71
Jamadoba	1.38	1.33	1.27	1.36	1.24	–	0.93	0.84	0.80	0.78	0.88	1.07
Total	3.89	4.05	4.80	5.31	5.18	5.24	1.99	1.96	2.05	2.19	2.31	2.55
Grand total	22.69	22.74	23.00	22.23	22.00	21.07	12.12	11.75	11.92	10.89	10.01	9.72

Source

CCO. *Coal Directory of India* (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.19 Inter-modal split of coal movement: 1977/78 to 1999/2000

Mode	*1977/78*		*1995/96*		*1996/97*		*1997/98*		*1998/99*		*1999/2000*[a]	
	MT	*%*	*MT*	*%*	*MT*	*%*	*MT*	*%*	*MT*	*%*	*MT*	*%*
Rail	78	78	156	56	165	57	176	57.14	164	54.85	127	56.44
Road	17	17	54	19	52	18	54	17.53	53	17.73	37	16.44
Belt	2	2	6	2	6	2	9	2.92	11	3.68	7	3.11
Ropeway	1	1	6	2	5	2	6	1.95	6	2.01	4	1.78
Merry-go-round	2	2	56	21	59	21	63	20.45	65	21.74	50	22.22
Total	100	100	280	100	287	100	308	100.00	299	100.00	225	100.00

MT - million tonne
[a] April-November

Source
MoC. 2000. ***Annual Report 1999/2000.*** New Delhi: Ministry of Coal.

Table 1.20 Capacity and traffic handled at major ports (million tonnes): 1998/99

Port	*Capacity*		*Traffic handled*	
	All commodity	*Only coal*	*All commodity*	*Only coal*
Calcutta	8.3	–	9	–
Chennai	26.6	–	35	9.9
Haldia	22.7	6.8	20	7.1
Jawaharlal Nehru	16.0	–	12	–
Kandla	37.0	–	41	0.7
Kochi	13.0	–	13	0.2
Mormugao	18.7	–	18	0.3
Mumbai	31.0	–	31	–
New Mangalore	17.0	–	14	0.1
Paradip	11.0	4.8	13	7.9
Tuticorin	8.0	4.0	10	4.5
Vishakapatnam	30.0	–	36	8.4

Source
MoST. 1999. ***Basic Port Statistics of India 1998/99.*** New Delhi: Ministry of Surface Transport.

Table 1.21 Average cost of production (rupees per tonne) of the CIL (Coal India Limited) and the SCCL (Singareni Collieries Company Limited) coal: 1993/94 to 1998/99

	Average cost of production	
Year	*CIL*	*SCCL*
1993/94	364.4	487.00
1994/95	380.5	543.00
1995/96	412.7	643.00
1996/97	442.1	731.56
1997/98	480.8	775.78
1998/99	502.4	826.30

Source
MoC. 2000. *Annual Report 1999/2000*. New Delhi: Ministry of Coal.

Table 1.22 Average pithead unit value (rupees per tonne) of coal: 1974/75 to 1997/98

Year	*Pithead unit value*
1974/75	70.42
1979/80	118.95
1984/85	206.88
1989/90	278.51
1990/91	277.89
1991/92	354.90
1992/93	355.41
1993/94	433.21
1994/95	442.00
1995/96	505.50
1996/97	576.00
1997/98	600.30

Note
The figures are up to March for all the years.

Source
CCO. *Coal Directory of India* (various issues).
Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.23 Average pithead prices (**rupees per tonne**) of the CIL (Coal India Limited) and the SCCL (Singareni Collieries Company Limited) coal: 1991 to 1999

	Average pithead price	
Date of revision	*CIL*	*SCCL*
27 December 1991	322.00	388.00
17 February 1993	364.00	434.00
19 June 1993	381.00	452.00
01 April 1994	381.00	482.00
17 June 1994	401.00	503.00
01 April 1996	469.00	503.00
19 April 1996	469.00	530.00
20 October 1996	498.54	530.00
12 November 1996	498.54	529.42
19 March 1997	498.54	710.59
01 April 1997	553.37	710.59
01 October 1997	559.02	710.59
21 August 1998	586.19	710.59
29 August 1998	586.19	753.31
05 January 1999	590.05	753.31
31 May 1999	595.84	753.31
19 September 1999	595.84	775.62

Source
MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table 1.24 Annual average import price of coal (dollars per tonne)

Country	*1994*	*1995*	*1996*	*1997*[a]
Australia	32.30	39.37	38.07	35.4
USA	36.48	39.19	37.21	36.5

[a] January-December

Note
Coal (Australian), thermal, 12 000 btu/lb, less than 1% sulphur, 14% ash, free-on-board piers, Newcastle/Port Kembla
Coal (US), thermal, 12 000 btu/lb, less than 1% sulphur, 12% ash, free-on-board piers, Hampton Road/Norfolk

Table 1.25 Customs duty structure on imported coal: 1999/2000

Import of coal	*Current duty*
Coking coal of ash content less than 12%	5% basic customs duty
Special customs duty	5%
Special additional duty	4%
Non-coking coal, coke, coking coal of ash content above 12%	15% basic customs duty
Surcharge on basic customs duty	10%
Special additional duty	4%

Source
MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table 1.26 Royalty (million rupees) paid on coal by states: 1991/92 to 1998/99

Year	*West Bengal*	*Bihar*	*Orissa*	*Maharashtra*	*Madhya Pradesh*	*Uttar Pradesh*	*Assam*	*Andhra Pradesh*	*Total*
1991/92	100.1	3,178	435	610	2,402	475	6.4	354	7,561
1992/93	87.2	5,043	631	1,089	3,845	668	5.4	1,000	12,369
1993/94	106.3	5,551	728	1,111	3,696	706	4.4	2,913	14,815
1994/95	95.9	6,131	1,041	1,597	4,389	874	4.2	1,445	15,577
1995/96	78.2	6,583	1,808	2,179	6,668	1,135	215.9	1,753	20,420
1996/97	108.7	6,828	1,854	2,003	6,841	1,214	99.2	1,971	20,919
1997/98	126.4	6,590	2,276	2,048	6,636	1,024	61.1	2,781	21,542
1998/99	97.6	6,079	2,289	1,846	6,751	868	51.7	2,002	19,984

Source
MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table1.27 Revised rates of royalty (rupees per tonne)

Coal group	*Royalty from 1 August 1991*	*Royalty from 11 October 1994*
Group-I (Coking coal SG I II, WG I	150	195
Group-II (Coking coal WGII, III, SC I II Non-coking A, B)	120	135
Group-III (Coking coal WGIV, Non-coking C)	75	95
Group-IV (Non-coking D, E)	45	70
Group-V (Non-coking F, G)	25	50
Group-VI (Coal produced in Andhra Pradesh)	70	75

Note
Royalty has not been revised since 1994.

Source
MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table 1.28 Selling price of coal in respect of the CIL (Coal India Ltd) and subsidiaries (**rupees per tonne**): 20 April 2000

Subsidiary	*Characteristics*	*Grade*	*Steam coal and rubble*	*Slack coal and washery middlings*	*Run-of-mine coal*
Non-coking coal					
Eastern Coalfields Ltd (Ranigunj)	Coal produced in Annexure I collieries	A	1,362	1,274	1,262
		B	1,293	1,204	1,193
		C	1,116	1,028	1,016
		D	923	830	823
Coal produced in other collieries of Ranigunj Coalfields	Long-flame coal	A	1,248	1,158	1,148
		B	1,184	1,094	1,084
		C	1,025	935	925
		D	849	755	749
	Non-long-flame coal	A	1,176	1,086	1,076
		B	1,114	1,024	1,014
		C	954	864	854
		D	780	686	680
		E	576	482	476
		F	479	385	379
		G	371	277	271
Eastern Coalfields Ltd (Salanpur)	Non-long-flame coal	A	1,170	1,080	1,070
		B	1,063	973	963
		C	891	802	791
		D	731	637	631
		E	576	482	476
		F	479	386	379
		G	371	278	271
Eastern Coalfields Ltd (SP Mines)	Coal produced in Annexure I collieries	A	1,299	1,210	1,199
		B	1,184	1,095	1,084
		C	1,005	916	905
		D	836	742	736
Eastern Coalfields Ltd (SP Mines)	Long-flame coal	A	1,190	1,101	1,090
		B	1,086	997	968
		C	923	834	823
		D	768	675	668
	Non-long-flame coal	A	1,118	1,028	1,018
		B	1,015	925	915
		C	853	763	753
		D	700	606	600
		E	576	482	476
		F	479	385	379
		G	371	277	271

Continued

Table 1.28 continued

Subsidiary	*Characteristics*	*Grade*	*Steam coal and rubble*	*Slack coal and washery middlings*	*Run-of-mine coal*
Eastern Coalfields Ltd (Mugma)	Long-flame coal	A	1,190	1,100	1,090
		B	1,086	996	968
		C	923	833	823
		D	768	674	668
	Non-long-flame coal	A	1,118	1,029	1,018
		B	1,015	926	915
		C	853	764	753
		D	700	606	600
		E	576	482	476
		F	479	386	379
		G	371	278	271
Eastern Coalfields Ltd (Rajmahal Project)	Long-flame coal	D	932	838	832
	Non-long-flame coal	E	739	646	639
		F	643	550	543
		G	535	441	435
Western Coalfields Ltd	Long-flame coal	A	1,096	1,046	1,036
		B	1,038	988	978
		C	974	924	914
		D	923	869	863
	Non-long-flame coal	A	1,033	983	973
		B	975	925	915
		C	912	862	852
		D	859	805	799
		E	685	671	665
		F	574	560	554
		G	438	424	418
South-Eastern Coalfields Ltd	Coal produced in Annexure I collieries	A	1,134	1,079	1,068
		B	1,032	971	966
		C	872	817	806
		D	748	694	688
	Long-flame coal	A	1,030	980	970
		B	938	888	878
		C	793	743	733
		D	685	631	625
	Non-long-flame coal	A	967	917	907
		B	875	825	815
		C	730	680	670
		D	621	567	561

Continued

Table 1.28 continued

Subsidiary	*Characteristics*	*Grade*	*Steam coal and rubble*	*Slack coal and washery middlings*	*Run-of-mine coal*
		E	465	451	445
		F	375	361	355
		G	274	260	254
Central Coalfields Ltd and Bharat Coking Coal Ltd	Long-flame coal	A	1,079	1,029	1,019
		B	982	932	922
		C	830	780	770
		D	716	662	656
	Non-long-flame coal	A	1,012	962	952
		B	916	866	856
		C	764	714	704
		D	649	595	589
		E	487	473	467
		F	393	379	373
		G	287	273	267
Northern Coalfields Ltd	Long-flame coal	A	1,088	1,038	1,028
		B	991	941	931
		C	837	787	777
		D	723	669	663
	Non-long-flame coal	A	1,021	971	961
		B	924	874	864
		C	770	720	710
		D	655	601	595
		E	492	478	472
		F	396	382	376
		G	289	275	269
Mahanadi Coalfields Ltd	Long-flame coal	A	992	942	932
		B	903	853	843
		C	765	715	705
		D	663	609	603
	Non-long-flame coal	A	929	879	869
		B	840	790	780
		C	702	652	642
		D	599	545	539
		E	448	434	428
		F	361	347	341
		G	263	249	243
Coking coal					
Bharat Coking Coal Ltd	Steel	I	1,800	1,750	1,740
(For collieries listed in Annexure III)	Steel	II	1,513	1,463	1,453
	Washery	I	1,319	1,269	1,259

Continued

Table 1.28 continued

Subsidiary	Characteristics	Grade	Steam coal and rubble	Slack coal and washery middlings	Run-of-mine coal
	Washery	II	1,103	1,053	1,043
	Washery	III	831	781	771
	Washery	IV	777	727	717
Bharat Coking Coal Ltd	Steel	I	1,601	1,551	1,541
	Steel	II	1,347	1,297	1,287
	Washery	I	1,175	1,125	1,115
	Washery	II	984	934	924
	Washery	III	743	693	683
	Washery	IV	695	645	635
Eastern Coalfields Ltd	Washery	I	1,293	1,203	1,193
	Washery	II	1,088	999	988
	Washery	III	830	741	730
	Washery	IV	779	690	679
Central Coalfields Ltd	Washery	I	1,175	1,125	1,115
	Washery	II	984	934	924
	Washery	III	743	693	683
	Washery	IV	695	645	635
South-Eastern Coalfields Ltd	Washery	I	1,084	1,034	1,024
	Washery	II	908	858	848
	Washery	III	687	637	627
	Washery	IV	644	594	584
Western Coalfields Ltd	Washery	I	1,084	1,034	1,024
	Washery	II	908	858	848
	Washery	III	825	775	765
	Washery	IV	688	638	628
Bharat Coking Coal Ltd	Semi-coking	I	1,274	1,224	1,214
(For collieries listed in Annexure III)	Semi-coking	II	1,065	1,015	1,005
Bharat Coking Coal Ltd	Semi-coking	I	1,135	1,085	1,075
	Semi-coking	II	950	900	890
Eastern Coalfields Ltd	Semi-coking	I	1,336	1,247	1,236
(Ranigang)	Semi-coking	II	1,124	1,034	1,024
Central Coalfileds Ltd	Semi-coking	I	1,135	1,085	1,075
	Semi-coking	II	950	900	890
All subsidiaries	Semi-coking	I	1,084	1,034	1,024
	Semi-coking	II	908	858	848

Source
CIL. 2000. Sales and Marketing: 2000. Price list April 2000. New Delhi: Coal India Ltd.

Table 1.29 Plan expenditure and the share of coal (million rupees)

Five-Year Plan	*Plan expenditure*[a]	*Share of coal*	*Total energy*[b]
First (1951-56)	19,600	–	3,861.2 (19.7)
Second (1956-61)	26,700	507.3 (1.9)	3,310.8 (12.4)
Third (1961-66)	85,800	1,115.4 (1.3)	15,873.0 (18.5)
Fourth (1969-74)	157,800	1,104.6 (0.7)	33,453.6 (21.2)
Fifth (1974-79)	394,300	11,434.7 (2.9)	99,363.6 (25.2)
Sixth (1980-85)	1,092,900	38,251.5 (3.5)	307,104.9 (28.1)
Seventh (1985-90)	2,202,200	70,470.4 (3.2)	621,020.4 (28.2)
Eighth (1992-97)[c]	4,341,000	104,184.0 (2.4)	1,150,365.0 (26.5)

[a] expenditure at current price at the base year of the respective plans
[b] total energy includes power, coal, oil and gas, and new and renewable energy sources.
[c] outlay

Note
Figures in parentheses are percentages.

Source
Ninth Five-Year Plan. 1997-2002. Volume II. Thematic Issues and Sectoral Programmes.
New Delhi: Planning Commission, Government of India.

Table 1.30 Annual Plan expenditure during the Eighth Five-Year Plan and actual expenditure (million rupees)

Year	*Coal India Ltd*	*Singareni Collieries Company Ltd*	*Science and technology regional exploration and others*
1992/93			
Budget estimate	18,500.0	4,090.0	230.0
Revised	17,600.0	4,090.0	230.0
Actual expenditure	18,084.7	4,064.5	182.4
1993/94			
Budget estimate	19,010.0	6,422.0	170.0
Revised	17,200.0	5,600.0	170.0
Actual expenditure	16,879.2	5,449.8	159.1
1994/95			
Budget estimate	20,629.0	4,834.0	235.0
Revised	18,500.0	5,500.0	229.9
Actual expenditure	16,045.6	5,165.8	48.4
1995/96			
Budget estimate	22,600.0	5,160.0	438.2
Revised	12,037.8	3,357.5	251.0
Actual expenditure	15,036.3	2,593.5	147.9
1996/97			
Budget estimate	21,430.0	5,389.7	528.0
Revised	13,108.3	3,250.0	280.0
Actual expenditure	15,304.5	2,500.6	280.7
1998/99			
Budget estimate	25,172.0	3,315.7	921.3
Revised	17,000.0	2,800.0	571.0
Actual expenditure	17,537.3	2,004.9	448.0
1999/2000			
Budget estimate	25,560.0	2,271.9	825.4
Revised	26,791.9	2,172.0	631.4
Actual expenditure	17,950.5	816.0	751.3

Source

MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table 1.31 Net budgetary support as percentage of actual plan expenditure in coal: 1992/93 to 1996/97

Year	*Net budgetary support (%)*
1992/93	13.54
1993/94	8.50
1994/95	12.55
1995/96	12.59
1996/97	7.41

Source
MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Table 1.32 Availability and estimated sectorwise consumption of raw coal (**million tonnes**): 1990/91 to 1997/98

Items	*1990/91*	*1991/92*	*1992/93*	*1993/94*	*1994/95*	*1995/96*	*1996/97*	*1997/98*
Availability								
Production	213.90	232.80	242.00	248.68	257.8	273.4	286.1	297.2
Imports[a]	5.71	5.92	6.26	7.10	8.3	8.9	9.5	9.5
Exports	0.10	0.11	0.13	0.10	0.1	0.1	0.1	0.1
Pithead stock (opening)	37.64	42.47	48.53	51.39	50.8	47.5	45.6	42.0
Pithead stock (closing)	42.47	48.53	51.31	50.75	47.5	45.6	42.0	41.5
Adjustment of pithead stock								
Industrial stock (opening)	6.21	5.25	5.50	0	0	0	0	0
Industrial stock (closing)	5.25	5.48	0	0	0	0	0	0
Available for industrial consumption after adjustment of off-take	213.30	228.87	241.79	255.90	269.2	284	299	307.1
Consumption/supply (raw coal)								
Steel and washery	30.91	34.03	37.30	37.63	38.6	39.1	39.8	39.8
Railways	5.24	5.06	4.34	2.00	0.67	0.3	0.1	0.1
Electricity (excluding middlings)	113.71	126.84	138.57	154.41	160.9	184.5	199.6	205.5
Cement	10.43	10.80	11.70	11.07	12.4	11.1	10.1	10.1
Cotton	2.58	1.96	1.90	1.81	1.8	1.2	1.3	1.3
Jute	0.12	0.12	0	0	0	0.1	0.1	0
Paper[b]	2.81	2.67	2.56	2.90	3.2	3.2	3.5	3.4
Brick	1.71	1.75	1.65	1.54	1.0	0.9	1.0	1.6
Coal for soft coke	1.20	1.03	0.97	0.44	0.3	0.3	0.3	0
Other industries	40.58	40.51	38.71	39.53	46.7	40.0	39.8	42.1
Colliery consumption	4.07	4.10	3.99	4.71	3.7	3.5	3.4	3.1
Total consumption	213.30	228.87	241.75	255.90	269.3	284.2	299.0	307.1

[a] only coking coal imports
[b] includes only rail despatches

Source
CCO. ***Coal Directory of India*** (various issues). Calcutta: Coal Controller's Organization, Ministry of Coal.

For more details, please see TEDDY ONLINE+ [Section: Coal (general)]

Table 1.33A Supply (**thousand tonnes**) of coal to steel plants: 1995/96 to 1996/97

Steel plant	1995/96					1996/97				
	Prime coking coal	*Medium coking coal*	*Blendable coking coal*	*Total*	*Boiler coal*	*Prime coking coal*	*Medium coking coal*	*Blendable coking coal*	*Total*	*Boiler coal*
Bhilai steel plant	1,088.3	1,381.5	239.2	2,709.0	629.9	892.4	1,273.2	205.0	2,370.6	779.4
Bokaro steel plant	978.0	992.4	7.8	1,978.2	1,674.5	900.1	1,252.1	0	2,153.0	1,602.9
Durgapur steel plant	726.9	548.4	21.1	1,296.4	384.4	622.0	448.6	8.7	1,079.3	549.3
Indian Iron and Steel Company	900.0	483.7	66.9	1,450.6	195.2	777.1	419.3	73.6	1,270.0	248.1
Rourkela steel plant	618.5	686.2	8.6	1,313.3	1,199.3	356.2	714.1	0	1,070.3	1,302.2
Steel Authority of India Ltd (Total)	4,311.7	4,092.2	343.6	8,747.5	4,083.3	3,547.8	4,108.1	287.3	7,943.2	4,481.9
Tata Iron and Steel Company Ltd	681.6	1,172.9	46.9	1,901.4	635.8	378.0	590.0	17.0	985.0	1,474.2
Visakhapatnam Steel Plant	20.9	915.8	0	936.7	1,194.4	75.7	750.5	0	826.2	1,351.8
Grand total	5,014.2	618.9	390.5	11,585.6	5,913.5	4,001.5	5,448.6	304.3	9,754.4	7,307.9

Source

CCO. 2000. ***Coal Directory of India 1999/2000***. Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.33B Supply (thousand tonnes) of coal to steel plants: 1997/98 to 1998/99

Steel plant	1997/98					1998/99				
	Prime coking coal	*Medium coking coal*	*Blendable coking coal*	*Total*	*Boiler coal*	*Prime coking coal*	*Medium coking coal*	*Blendable coking coal*	*Total*	*Boiler coal*
Bhilai steel plant	893	1,084	165	2,142	760	748	1,112	32	1,892	704
Bokaro steel plant	901	1,204	0	2,105	1,483	854	1,085	–	1,939	1,398
Durgapur steel plant	532	396	0	928	671	686	405	6	1,097	624
Indian Iron and Steel Company	636	356	42	1,034	209	659	257	48	964	175
Rourkela steel plant	344	570	0	914	1,364	360	590	–	950	1,292
Steel Authority of India Ltd (Total)	3,306	3,610	207	7,123	4,487	3,307	3,449	86	6,842	4,193
Tata Iron and Steel Company Ltd	900	1,427	3	2,330	1,450	1,079	1,479	–	2,558	1,400
Visakhapatnam Steel Plant	0	619	0	619	1,434	–	386	–	386	1,721
Grand total	4,206	5,656	210	10,072	7,371	4,386	5,314	86	9,786	7,314

Source

CCO. 2000. ***Coal Directory of India 1999/2000***. Calcutta: Coal Controller's Organization, Ministry of Coal.

Table 1.34 Sectoral offtake from the CIL (Coal India Ltd) and the SCCL (Singareni Collieries Company Ltd) (**million tonnes**): April-December 1999/2000

	CIL			*SCCL*		
Sector	*Target offtake*	*Actual offtake*	*Supply (%) against target*	*Target offtake*	*Actual offtake*	*Supply (%) against target*
Power	136.74	141.000	103	16.76	17.90	106.8
Steel	14.12	10.950	78	0	0	0
Locomotive	0	0.007	100	0	0	0
Cement	4.36	4.810	110	2.32	2.32	100.0
Fertilizer	2.79	2.390	86	0.44	–	-100.0
Others	29.58	28.990	98	2.68	1.91	71.3
Colliery consumption	1.93	1.670	86	0.26	0.22	84.6

Source

MoC. 2000. ***Annual Report 1999/2000***. New Delhi: Ministry of Coal.

Regulatory framework for the coal sector - a review

This paper presents the summary from a study report titled "Review of the regulatory framework in Coal Industry in India". This study was jointly undertaken by Tata Energy Research Institute (TERI), New Delhi and International Mining Consultants, United Kingdom in 1999-00 and was sponsored by the Ministry of Coal, Government of India.

The primary purpose of the report was to analyse the current regulatory framework which will assist GoI to formulate an action plan for the implementation of a regulatory regime, which will (a) free existing public sector coal companies from avoidable procedural constraints; (b) encourage private sector participation in the coal sector; and (c) make the regulatory framework investor friendly.

The analysis of the existing regulatory framework and the preparation of recommendations was a five-stage process. These stages were:

- Establishment of the approach to the task
- Identification of all legislation pertinent to the coal sector
- Review of the legislation and procedures in the context of perceived sectoral policy
- Preparation of options for change
- Preparation of recommendations for change

Nine topics for analysis, which broadly reflect the process of coal development from prospecting to coal sales, were selected. They are:

- Mineral Rights
- Surface Rights
- Prospecting / Mining Operations / Health and Safety
- Financial / Fiscal
- Labour / Trade Unions / Employee Welfare / Compensation
- Environment
- Forests
- Resettlement / Rehabilitation
- Marketing / Distribution / Transportation / Sales

In order to prepare recommendations for a regulatory framework, it is necessary to identify the policy for the sector. In India, there is no complete, clearly defined policy for the coal sector. Consequently, several outstanding issues must be resolved by the Government before a meaningful programme of regulatory reform can be initiated.

They include:

- The quality, location and extent of coal reserves to be made available to the private sector
- Restrictions on foreign investment in the coal sector

In addition the role to played by Coal India Limited in the foreseeable future needs to be decided.

Resolution of these issues will assist in the preparation of an "Action Plan" for regulatory reform.

Several economic issues must be considered if the likely interest by potential investors is to be assessed. They include:

(a) The poor economics of electricity generation, transmission and distribution.
(b) Large captive generation by industrial units decreasing the demand on the utilities.
(c) Increasing coal imports.
(d) The cost of transporting coal by rail.
(e) Negative international investment conditions for coal projects.

These negative factors for new investment in the coal sector should be borne in mind as it would be unrealistic to suggest that regulatory reform in itself will stimulate investment.

II Mineral Rights.

In India, minerals are owned by the States. However, the Constitution provides that the Central Government may exercise the power to regulate minerals should it elect to do so. The Central Government has elected to use this power by enacting the Mines and Minerals (Regulation and Development) Act 1957 (MMRDA)which designates (in the First Schedule) coal, and some other minerals, as minerals under the direct control of the Central Government. The Mineral Concession Rules 1960 (MCR) were implemented soon after to provide for the administration of mineral titles. Another important piece of legislation with respect to coal rights is the Coal Bearing Areas (Acquisition and Development) Act 1957 (CBAADA). This legislation provided for greater public control over coal production by empowering the Central Government to acquire unworked land containing or likely to contain coal deposits.

This legislative framework has been analysed with respect to a number of important parameters. These include:

(a) Independence of agency responsible for administering mineral rights.
(b) Exemptions for PSEs.
(c) Eligibility Criteria for Coal Rights.
(d) Reserved Areas.
(e) Prospecting Rights.
(f) Mining Rights.
(g) Transfers.
(h) Assignment.
(i) Reporting and Confidentiality.
(j) Discretionary Powers.

The current legislation is deficient, to varying degrees, in all categories if private sector investment is to be encouraged. The most significant problems relate to the independence of the administering agency, the exemptions/privileges for PSEs, priority and exclusivity for mineral titles, and discretionary powers. Currently the primary administering agency is the Department of Coal who are at the same time the shareholder representative on the board of the PSE, Coal India Limited. The PSEs are also the beneficiary of several special privileges including exemption from the requirement to obtain prospecting licences with all the associated procedural delays. The standard provision of "first come, first served" for the acquisition of mineral titles is unnecessarily qualified. Furthermore, normal international practice is for titles to be granted on an exclusive basis for all minerals in a given area rather than for specified minerals. This usual procedure avoids the problem of overlapping mineral titles for a given tract. A major problem with the current legislation from the point of view of a potential investor is the discretionary nature of many of the provisions. While many of these apparent discretionary powers have been curbed by the courts, they still appear in the legislation.

Geological information acquired by the Government from the holders of surrendered mineral rights is currently not readily available to potential investors. The practice of attempting to recover the direct cost of the acquisition of this data is counter-productive. All such information is part of the geological infrastructure of India and it should be used to attract new investment in minerals. Normal international practice is for such information to be available for the cost of reproduction.

"Coal blocks", as were awarded for captive mining, have not been a success as most potential investors have not progressed towards production. Reasons for this include the size of the blocks, the location of the blocks, and the reserves available. These drawbacks can be attributed in large part to the selection criteria which required that the blocks would not be required by CIL for production through the year 2036 and the proviso that the coal reserves were to be for captive use.

The block concept should be radically modified. CIL should be required to apply for PLs and MLs subject to the current legislation and all areas not taken made available to potential investors. A system of competitive bidding for new areas for prospecting and development should be initiated for the allocation of these areas.

Important recommendations are:

- The majority of board positions in the PSEs should be held by persons other than officials of the administering Ministry.
- Coal Bearing Areas (Acquisition and Development) Act should be retained for an interim period.
- "First come, first served" should be the non-discretionary principle for issuance of mineral rights once the sector is fully liberalised.
- Data both from the Geological Survey of India and with regard to areas where mineral rights have been surrendered should be immediately available to the public at nominal cost.

III Surface Rights.

The acquisition and physical possession of land, referred to as surface rights in this report, is a prime prerequisite for commencement of a mining operation. The process for the acquisition of surface rights depends on the category of land to be acquired.

Based on ownership, land can be broadly divided into tenancy (private) land, State owned forest land and State owned revenue land. State owned land is acquired by administrative procedure in the case of revenue land and by procedures under the Forest (Conservation) Act 1980 in the case of forest land. In the first case there appear to be few difficulties and in the second case a full analysis is presented in the chapter on "Forests".

Acquisition of tenancy land may be by procedures under the Land Acquisition Act 1894 or by direct negotiation. In addition, PSEs are able to take advantage of the provisions of the Coal Bearing Areas (Acquisition and Development) Act 1957 (CBAADA) for the acquisition of surface rights (as well as mineral rights) and the Land Acquisition Act. As the Land Acquisition Act is available only for a "public purpose", any private sector investor is, in theory at least, restricted to the use of direct negotiation for acquisition of surface rights for tenancy land. Some States have adopted procedures or enacted Land Codes which assist investors to acquire surface rights.

Land acquisition procedures without exception are prone to delay and have resulted in project delays and /or abandonment.

The main recommendations are that:

- The provisions of the CBAADA for acquisition of surface rights be retained on an interim basis.
- Those States, desirous of investment which do not already have suitable provisions in their land codes, make such provisions in their land codes to assist the private sector.

IV Prospecting/Mining Operations/Health and Safety.

This chapter of the report deals with the regulatory framework as it relates to prospecting, obtaining a permit to mine and mining operations to closure.

The legislation primarily concerned with these matters is contained in:

(a) Mines and Minerals (Regulation and Development) Act 1957 (MMRDA)
(b) Coal Mines (Conservation and Development) Act 1974 (CMCDA)
(c) Colliery Control Order 2000 (CCO 2000)
(d) Mines Act 1952 (MA)

There are a number of supplementary rules, orders and notifications which provide for additional administrative requirements and procedures.

Prospecting is largely unregulated with regard to procedures except for requirements for site, environmental and forest clearances which are addressed in the appropriate chapters.

Permission to open a mine is granted by the issuance of a Mining Lease subject to certain preconditions and following a number of clearances. The mine plan must be cleared by the Empowered Standing Committee in the Department of Coal;

permission must be granted by the Coal Controller and the Directorate General of Mines safety (DGMS) must be notified. Concurrently prior requirements for surface rights, environmental and forest clearances must have been obtained.

One issue that relates to the extraction of coal is the conservation of coal which is a topic specified under both MMRDA and CMCDA. There exists in the Department of Coal, a Coal Conservation and Development Advisory Committee with the presumed mandate of ensuring coal conservation. The Committee has met infrequently to discuss coal conservation which is probably a reflection of the lack of a coal conservation policy. The requirement for coal conservation should not impinge on good mining practice in the light of the generally accepted principle that least cost energy resources should be utilised first as there may be no need to utilise the high cost resources as technologies may change.

The monitoring of mining operations for compliance with approved mining plans is currently non-existent.

Health and safety in mining operations are principles that are accepted world-wide. However they are rarely considered in the context of efficiency and profitability. The current legislation has been in place with only minor amendments for almost fifty years. In common with legislation world-wide from that period the legislation is largely prescriptive. As such it tends to stifle management incentive and impede performance.

The regulatory framework is reviewed under two broad headings – "Direct Impediments to Efficiency" and "Indirect Impediments to Efficiency". Direct impediments include delays in obtaining permissions/exemptions/approvals for various routine operations, the time required to obtain approvals for the introduction of new equipment and the lack of legislation for the operation of opencast mines. Indirect impediments include inefficiencies deriving from unclear demarcation of duties and responsibilities for owners, agents and managers; safety policies and regulations in need of review; restricted access accident inquiries; failure to follow through on the recommendations of safety conferences; and inadequate training in safety matters.

While occupational health needs are well met in the coal fields, there is a need to update the standards in view of the changing technology in the industry.

The main recommendations are that:

- A coal conservation policy and guidelines should be developed
- Regulations for opencast mining should be established
- In the longer term, a new Mines Act should be drafted to reflect modern approaches to health and safety in both opencast and underground mines.

V Financial/Fiscal Matters.

In reviewing the financial and fiscal framework the consultants have been cognisant (a) that this framework is largely not within the purview of the client, and (b) that the client had some reservations as to whether these topics were within the terms of reference. Consequently the fuller treatment is reserved for those aspects where the client has some authority e.g. royalty.

The financial and fiscal framework should provide for:

(a) Equitable sharing of project benefits between the investor and the Government;
(b) An internationally competitive fiscal regime if foreign investment is desired;
(c) Stability of the tax regime.

The first provision is difficult as investors and governments have different objectives for a project. While the investor is primarily seeking return on investment, the government is seeking both tax revenues and other benefits e.g. employment. Frequently governments tend to try to maximise the direct tax benefits of a mining operation but this can be counter-productive as it will discourage the initial investment. Typically, the principal taxes imposed on the coal sector would include royalty and corporate income tax.

Financial issues include equity holding, joint ventures, and financial incentives for investors and lenders. Current legislation limits foreign direct investment in new projects to 74% and in captive mining projects to 100%. These provisions are welcome but it is noted that the MMRDA does not permit foreign companies to obtain mining rights. To date, there are no joint ventures between PSEs and the private sector. Current corporate restrictions on CIL require that CIL remain the majority partner in any joint venture. This provision discourages the private sector from seeking joint ventures. At present, there are no coal sector specific financial incentives. Consideration could be given to extending the benefits of infrastructure status to the coal industry on an interim basis pending formulation of financial incentives currently under consideration for the whole mining sector. Incentives for lenders are limited but consideration could be given to declaring the coal sector to be a sector that promotes social and economic welfare thereby making lenders to the sector eligible for a number of benefits.

Fiscal matters relate primarily to royalty and corporate taxation. The topic of royalty raise two primary issues – the basis and the rate. Currently royalties are assessed on an *in rem* basis i.e. on a per tonne basis. More commonly, royalties are collected on an *ad valorem* i.e. a percentage of the value of the product. Combinations of the two systems also exist. The *ad valorem* basis is preferred as, while it is not ideal, it does take some account of the fluctuating value of the commodity. Furthermore it does not require some arbitrary grading of the coal. Current royalty rates being paid in India average about 12% of the value of the product while international royalty rates are usually lower. It should be noted that in many countries, the owner of the minerals[1] in the ground, also derives income from other taxes. This is not currently the case in India.

Corporate income tax rates in India are higher than those obtaining in most coal mining countries. In addition, and perhaps more importantly, the deductions from gross income for the determination of taxable income are both fewer in number and less in percentage terms.

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[1] **In India, this is the States. A comparable situation exists in Australia and Canada.**

Various other fiscal matters are reviewed. Included are double taxation agreements, ring fencing, tax stability and international competitiveness.

The main recommendations are that:

- Restrictions limiting the share in joint ventures with CIL subsidiaries should be removed.
- Coal mining should receive all financial benefits that are awarded to the mineral sector.
- Royalties should be subject to a detailed review as to mode of calculation and rate.
- If India wants to be internationally competitive, revisions to improve the fiscal regime for the investor should be made.

VI Labour/Trade Unions/Employee Welfare/Compensation.

The main elements of the regulatory framework as it relates to labour are statutory employment rights, trade union rights, the collective bargaining process, terms and conditions of employment, dispute resolution and contract labour. Many of these elements of the work arrangements reflect the development of a nationalised industry of many years.

There is a extensive legislation ensuring employee rights which are not inappropriate or unduly burdensome. However changes should be considered in three areas. Payment of bonuses no longer reflects the original intent of the bonus schemes. Bonus payments have become an entitlement. Settlement of grievances under the Industrial Disputes Act 1947, while sound in principle, can in practice be extremely slow – some cases take years to resolve. Currently employment rights are incorporated into many different pieces of legislation – more than eight in number. It would be preferable to draft a new Employment Rights Act.

Trade Union rights and liabilities are governed by the Trade Unions Act, 1926 which broadly follows the UK legislation of that period. This Act has a very low hurdle for registration of only seven members. It is accepted, even by union leaders that this level is too low. Legal immunities in the Act are such that strike action can be taken without the balloting of members. It would be desirable to require balloting prior to strike action as is the case across the EU. There is currently no statutory basis on which Trade Unions may claim the right to be recognised for bargaining purposes. Currently there is a great deal of uncertainty regarding membership in the Trade Unions which creates further difficulty with the decision to recognise any given union.

Collective bargaining for the coal industry is presently carried out within the Joint Bipartite Committee for the Coal Industry (JBCCI), a body called into being from time to time by the Department of Coal. JBCCI is constituted from the operating companies and the five major unions. The collective agreements, which emerge from JBCCI, are the National Coal Wage Agreements (NCWA). This arrangement has worked satisfactorily in the past but it fails to take into account the varying abilities of individual subsidiaries of CIL to provide the agreed benefits. In future, it will be necessary for coal producers to establish their own agreements based on ability and willingness to pay.

India has a comprehensive and highly developed system for the resolution of both individual and collective employment disputes. As liberalisation of the sector prompts a move away from the JBCCI, it is likely that a number of disputes will arise in the transitional period. The main problem for resolution of these disputes will lie with delays in the Labour Courts attributable to vacancies for Presiding Officers and failure to adhere to timetables.

There are presently restrictions on the use of contract labour in coal mines pursuant to a Notification under the Contract Labour (Regulation and Abolition) Act, 1970. These restrictions are damaging to existing producers and to the prospects of attracting new investment into the sector. This second point is very important as it is likely that a preferred entry into the coal sector – at least initially – for the private sector might well be through contracting.

The issue of uneconomic capacity will be of increasing importance as access to public funds is withdrawn. It will be necessary to employ the existing consultative process at mine level diligently, to design an adequate benefits package for redundant manpower, and possibly to set up a fund dedicated to creating new employment in coal field areas.

The main recommendations are:

- The law regarding employment rights should be codified.
- The threshold for Trade Union recognition should be raised.
- Responsibility for collective bargaining should pass to the CIL subsidiaries
- The restrictions, both statutory and contractual, on the employment of contract labour should be abolished

VII Environment.

A legal framework for the management of the environment was initiated in the early 1970s in India and now consists of:
(a) The Water (Prevention and Control of Pollution) Act 1974
(b) The Water (Prevention and Control of Pollution) Cess Act 1977
(c) The Air (Prevention and Control of Pollution) Act 1981
(d) The Environment (Protection) Act 1986
(e) The Public Liability Insurance Act 1991

A number of specific standards for air and water, which are to be maintained in India, supplement this legislation. However, ambient air quality standards, effluent standards, and noise standards for specifically for coal mines, developed by the Central Pollution Control Board (CPCB), have not yet been notified.

The environmental framework is reviewed specifically with respect to:

(a) Site and environmental clearance for mining projects.
(b) Restoration of degraded land in mining areas.

(c) Environmental protection during closure of mines.
(d) Monitoring and enforcement of various laws for environmental protection.

The review has confirmed that the legislation is, with minor exceptions, well suited to the management of the environment. Most difficulties arise from procedural inadequacies. There are many procedural requirements prescribed in various notifications and guidelines. These primarily relate to the requirements for consents to establish a mining project and the subsequent recurring consents to operate. While there are clearances unrelated to environment e.g. approval of a mining plan by DoC, two of the most important environmental requirements are a Public Hearing and an Environmental Impact Assessment (EIA).

The most serious environmental impact of coal mining is on the land. This land degradation can be attributed to abandoned mines, currently operating mines and future mining operations. Abandoned mines, numbering more than 500, are mostly in the Jharia and Raniganj coal fields. Various plans for the restoration of the degraded lands have been proposed but no major restoration has been undertaken. Various cost estimates have been developed but full analysis as to whether the restoration would be cost effective has not been completed. Restoration could be funded by a levy on coal production. Current and future operations are subject to conditions with regard to reclamation of the site after mining. However in practice the enforcement of this conditionality is lacking. In many countries, the operator of a coal mine is required to submit a bond/guarantee ,as a condition of operating, which will provide funds for the authorities to undertake reclamation should the operator fail to do so.

Mine closure is not adequately addressed in the current environmental requirements. Preparation for closure is something, which must be considered from the day the mine opens. There is a need to develop procedures that pertain to the environmental aspects of mine closure.

The monitoring and enforcement of environmental requirements is lax while at the same time penalties for failure to comply are nominal.

The main recommendations are that:

- The establishment of some form of Reclamation Trust Fund/Bond be a requirement for consent to operate a mine.
- Monitoring agencies should be strengthened.
- Monetary penalties for failure to comply with environmental requirements should be substantially increased.

VIII Forests.

The major Acts and their rules, guidelines, and policies which directly apply to the management of the Forests and Wildlife are:

(a) Indian Forest Act, 1927
(b) Wildlife Protection Act 1972 (as amended up to 1991) with its many Rules.
(c) Forest (Conservation) Act 1980
(d) Forest (Conservation) Rules 1981

(e) Environment (Protection) Act 1986 and Rules (discussed under the Environment Section).
(f) National Forest Policy 1988

The Forest Conservation Act and associated Rules had as an important objective the reversal of deforestation in India. The legislation covers dereservation/diversion of forest land, use of forest land for non-forest purposes, assignment of forest land and clearing of forest land. As coal mining is a non-forest use of forest, the provisions of this legislation are very important to the coal sector.

The important topics are:

(a) Diversion of Forest Land
    - Preparation and Submission of Proposals
    - Clearance Process.
(b) Compensatory Afforestation
(c) Forest Compensation (Cost-benefit Analysis)
(d) Schedule of Lands

Diversion of forest land is considered by the Central Government based on a proposal prepared to a prescribed format. While the data required for the proposal is reasonable, preparation of the proposal is time consuming. This is partly due to the amount of data required but also reflects the lack of knowledge at both the level of the coal company and the responsible authorities. Furthermore forest boundaries are frequently in dispute.

Compensatory afforestation is one of the most important stipulations in an approval for diversion of forest. Basically, there is a requirement that an equivalent area of non-forest land be identified by the project proponent and funds deposited with the State for implementing the compensatory afforestation. The two most significant problems are the difficulty in identifying land for compensatory afforestation and the failure of States to carry out the compensatory afforestation.

The diversion of State forest land reduces the area of forest available to the State for income generation. Many States have therefore started to require compensation from the project proponent for this loss of income and other incidental costs. Currently there are many variations in the methodology used for the computation of the compensation.

There is no provision for reversion of reclaimed land to the Forest Departments in a staged and/or partial process. Some areas are known to MoEF where mining will never be permitted but no schedule of these lands is available.

The main recommendations are:

- States should identify land suitable for compensatory afforestation.
- Clear guidelines should be issued by MoEF for determination of forest compensation.
- Partial and/or early reversion of forest land should be permitted.
- A schedule of lands where mining will not be permitted should be prepared.

IX Resettlement/Rehabilitation.

At the request of the client, a review of the current policies for resettlement and rehabilitation (R & R) was completed. The review, undertaken from the perspective of an investor, deals with R & R in the context of the impact on the planning process, land acquisition, the impact on operations and the impact on project viability.

R & R is a major challenge facing any investor in the coal sector. While there is no Central Government legislation or formal policy, some States have adopted legislation and others have adopted policies. Likewise some PSEs, including CIL, have R & R policies.

To the extent possible, the planning process should start at an early stage in close consultation with the affected people to minimise project impact. A key stage in the process is land acquisition from the point of view of compensation whether the compensation be cash, new land and/or employment. These matters must be settled as early as possible in the planning process.

Difficulties with R & R issues may have a severe impact on operations with consequent adverse financial results. R & R difficulties have been known to cause temporary mine closures and major modifications to mine plans. The difficulty of quantifying R & R costs at the feasibility stage is a deterrent to investment. It is proposed that a data-bank of R & R costing be established as soon as possible.

The main recommendations are:

- A National Policy for R & R should be adopted as a matter of urgency
- R & R planning should be integrated into mine planning from the earliest stages
- Coal India Limited, with DoC, should prepare a model to capture the true costs of R & R. This data should be publicly available.

X Marketing/Distribution/Transportation/Sales.

Coal has been considered a strategic mineral for over fifty years. Accordingly, for most of the period up to the present it has been under the Essential Commodities Act 1981 and the Colliery Control Order 1945 (CCO 1945). These two items of legislation have regulated the price, distribution, sales and utilisation. On 1st January 2000, the Colliery Control Order 2000 superseded the CCO 1945 and supposedly liberalised the price, distribution, sales and utilisation of coal. Such a move by the Government is in line with the gradual liberalisation of the coal sector. This liberalisation is evidenced by the move towards coal supply agreements by both producers and consumers.

CCO 1945 dealt at length with all aspects of the coal market from price through grades to distribution. CCO 2000 removes some of the provisions but fails to fully liberalise the commercial side of the coal sector. It retains the right of the Government to:

(a) Prescribe grades

(b) Set procedures for sampling
(c) Establish coal sizes
(d) Control production, and
(e) Set other parameters.

These provisions do not contribute to liberalisation of the coal markets. The CCO 2000 appears to fulfil no useful function and is in fact a deterrent to investment. Even if CCO 2000 is withdrawn, the coal sector will still be subject to the various Colliery Control Orders of the States. Full liberalisation will require the withdrawal of both CCO 2000 and the State Colliery Control Orders. (It should be noted that the inclusion of coal as an essential commodity under the Essential Commodities Act empowers the Government to take whatever measures are deemed necessary with regard to coal markets in an emergency situation.)

Various suggestions have been made for the establishing some form of regulatory body for coal pricing. While this move would be directly contrary to the move towards liberalisation of the sector, a temporary independent regulatory body would assist the transition to a fully liberalised market. Coal supply contracts will obviate the need for such a body.

While transportation of coal is beyond the scope of this review, it is noted that rail transport costs severely impinge on the competitiveness of domestic coal in the energy market. In India, freight rates subsidise passenger fares. They do not, therefore, reflect the true cost of moving coal within the country. More specifically, rail freight rates in India have risen more than 20% in constant terms over the past six years. This is in marked contrast to international rail freight rates, which have been falling even in current terms over the same period. A further anomaly is that freight rates in India decrease only marginally with distance while in other countries significant rate reductions appear as the distance increases.

The funding for the construction of sidings is a controversial point. Clearly coal companies do not wish to be burdened with this capital expense and the Railways have no way to recover a "siding capital expenditure". The charging of freight rates above the prescribed "rupees per tonne-kilometre" of the tariff schedule is prohibited.

The most important recommendations are:

- Colliery Control Order 2000 should be withdrawn
- A temporary regulatory body should be set up for coal pricing during the interim period of transition to a fully liberalised economy.
- Rail freight rates should be rationalised
- Contractual fuel supply agreements should be the business norm

XI Institutions.

The role of Government in mineral sector development has been changing as economies are liberalised. From owner/operators, Governments have become administrators. Their more usual primary functions are now:

(a) Establishing sectoral policy and strategy
(b) Defining and enforcing norms and regulations

(c) Administering mineral rights
(d) Providing reliable regional geological information
(e) Protecting the environment
(f) Integrating sound social practices into the sector

The current institutional structure, while generally consistent with a structure for these functions, is accustomed to facilitating the operations of the PSEs and has relatively little experience in administering a sector with significant private sector participation.

Sector administration is split between the Central Government and the States. Important Central Government ministries are the Ministry of Mines and Mineral MoMM), the Ministry of Environment and Forests (MoEF) and the Ministry of Labour (MoL). The Department of Coal (DoC), located within MoMM, is the primary administrator of the coal sector. MoEF has a major role in clearing and monitoring the environmental requirements associated with the coal sector. The Directorate General of Mines Safety (DGMS), situated in MoL, has the primary responsibility for all matters related to health and safety in the sector.

In the States, the departments responsible for mining, forests and the environment are integrated into the approval process for mineral rights, the issuance of permits for operations, and the monitoring thereof.

The possible role of independent regulatory bodies for the coal sector is examined and it is concluded that there is no need for permanent regulatory bodies as has been suggested. However, the establishment of an independent regulatory authority on a temporary basis will assist in the smooth transition to a fully liberalised economy.

XII Conclusions and Recommendations.

The recommendations, which have been developed from the review of the existing regulatory framework for the sector, are in many cases dependent on the policies to be adopted for the sector. Policy for the coal sector is currently in transition. On the demand side, some of the conditions for competition are already in place. On the supply side, the liberalisation of the sector is proceeding more slowly as the Government reportedly will continue to reserve discretionary powers with regard to private sector coal development. Similarly, the proposed criteria for access to coal reserves for the private sector are not consistent with the desire to attract new investment.

The three priorities for the review can be summarised as follows:

(a) Facilitate the operations of the existing public sector coal companies
(b) Evolve systems to encourage private sector participation
(c) Make the regulatory framework investor friendly.

The first priority primarily relates to administrative processes and is uncontroversial. There is scope for reduction of costs and operational constraints. The second priority will probably require some dismantling of the privileged position of the public sector companies to establish a more level playing field for the sector as a whole. Full definition of policy issues and the extent and timetable for sectoral reform will need to be established to make detailed recommendations for the introduction of regulatory changes associated with this priority. The third priority can be achieved where regulatory reform does not raise competition issues as identified under the second priority.

The most important conclusions reached are:

(a) The establishment of an arm's length relationship between DoC and the operating companies would encourage the development of commercial practices in the coal companies
(b) The retention of CIL's current structure and ownership is incompatible with full liberalisation of the coal sector.
(c) The current policy of corporatisation implies greater autonomy for CIL's operating subsidiaries and opens a range of options including:
    - privatisation of individual subsidiaries, or parts of their operations. Flexibility in packaging assets and liabilities might allow disposals of currently loss-making activities – the ICICI report on ECL explores some of the options;
    - partial divestments to create public sector/private sector partnerships. Current restrictions on foreign investment may need to be reviewed to secure full value from this approach.
(d) The currently proposed criteria and process for the identification and release of coal blocks for private sector projects are flawed and would deter new independent operators from entering the sector on any significant scale.
(e) The use of contractors to carry out the full range of mining operations has become increasingly common throughout the world and should be encouraged in India.
(f) The issue of uneconomic capacity is urgent.
(g) The economic issues will heavily influence the likely extent and shape of private sector participation in the coal sector, and must therefore be taken into account in determining the Action Plan for regulatory reform.

Particular emphasis is placed on the need for time-bound procedures in the regulatory framework with provisions for deemed granting of clearances/requests in the absence of response from the government authorities.

Regulatory Framework for the Coal Sector - A Review

P V Sridharan
TERI

Coal Industry - Organizational set-up

- Coal India Limited - Holding Company
  - with 7 coal producing subsidiaries
  - and 1 planning institute
- SCCL: A State Government PSE
- Captive mines to steel sector: IISCO, TISCO

Coal Reserves

- Net proved and recoverable reserves upto 600 m depth (billion tonnes)

Type	**Proved reserves**	**Net proved reserves**	**Net recoverable reserves**
Coking	14.0	12.1	4.4
Non–coking	53.0	41.7	27.9
Total	67.0	55.8	26.3

Coal Demand

(Million Tonnes)

Sector	**9th Plan 2001-02**	**10th Plan 2006-7**	2011-12
Steel & Coke oven	34	40	40
Power (V)	241	373	469
Power (C)	21	28	32
Cement	17	22	24
Others	41	48	
Total	354	511	620
Scenario 1 - 511 (28,000 MW)			
Scenario 2 - 411 (18,000 MW)			
Scenario 3 - 449 (16,000 MW)			
Indigenous supply - 400			

Coal Sector - Issues

- Issues affecting the coal sector
  - Large investment requirement to develop production capacity
  - Quantum of proved reserves need to be established every year for projectisation
  - Exploration activity to be stepped up
  - Uneconomic mines closure and retrenchement of workforce
  - Land degradation and other environmental impacts
  - Land acquisition and R&R problems
  - Possibility of large imports to meet supply - demand gap

Integrated Coal Policy

Committee on integrated coal policy: some major recommendations (1996)

- Exploration
  - Creation of a separate exploration fund through a surcharge on coal production
  - Creation of an independent body for acceleration of exploration efforts
- Pricing: Deregulation in phases
- New production capacity
  - Coal blocks should be approved on the basis of competitive bids
  - Appropriate regulatory mechanism should be set up to protect interests of all concerned
- Need to examine the organizational structure of CIL (Holding Co.)

Coal Sector - Reforms

- Broad agreements was reached between the World Bank & Govt. of India/CIL on a reform programme (as a part of the CSRP loan from WB)
  - A reform strategy would ensure that CIL would
    - invest only in the most profitable mining operations
    - phase out subsidies to loss-making operations in 5-7 years
    - 'outsource' all activities which can be obtained cheaper improve the quality of its coal supplies
    - make its operations environmentally and socially sustainable

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Coal Industry - Reforms (contd..)

- Encourage the development of a competitive coal market through
  - deregulation of coal pricing and distribution
  - reduction in import tariffs
  - investments by private investors
- Holding company would serve as the main conduit for the implementation of reforms aimed at converting subsidiaries into commercially viable coal companies.

Coal Sector - Policy

- At the time of nationalisation policy was to secure and maintain centralised government control
- Corporate structure, methods and approach established/evolved to meet the requirements of that policy
- Some modification in this policy have been done in the 1990s
  - budgetary support reduced
  - decontrol of coal pricing and distribution
  - Import tariffs drastically reduced (subsequently increased)
  - CMNA amended to allow private investment for captive mining
  - Further amendment recommended to extend private participation beyond captive mining

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Coal Sector - Policy Issues

- Policy issues directly relevant to Regulatory Framework Study (RFW)
  - The continuing role of the holding company
  - Further definition of what measures are proposed by way of 'corporatisation' of subsidiaries
  - Models for partnership with private sector participants
  - Any decisions regarding disinvestment

No guidance was available from MoC

Coal Sector - International Investment

- International investment in coal sector is likely to proceed only if:
  - Proven high quality reserves have been established
  - Infrastructure is available, or can be created, at competitive cost
  - Surface mining techniques can be employed
  - Investment is underwritten by long term supply contracts or at a minimum, markets for the output
  - Labour relations are well ordered and manageable
  - Social and environmental costs can be predicted and controlled
  - Mining and related rights are adequately secured by a legal and regulatory framework

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RFW Study - Purpose

- RFW study was jointly carried by TERI & IMC Ltd. UK.
- Broad objectives are:
  - free existing public sector coal companies from avoidable procedural constraints
  - encourage private sector participation in the coal sector
  - make the regulatory framework investor friendly

RFW Study - Topics

- Topics covered in the analysis:
  - Mineral rights
  - Surface rights
  - Prospecting/Mining Operations/Health & Safety
  - Financial/Fiscal
  - Labour/Trade Unions/Employee Welfare/Compensation
  - Environment
  - Forests
  - Resettlement/Rehabilitation
  - Marketing/Distribution/ Transportation/Sales

Coal Sector - Mineral rights

- Mineral are owned by the respective state govt.
- MMRD Act (1957) designates coal under direct control of central government
- CBA (AD) Act (1957) - empowers the govt. to acquire unworked land containing or likely to contain coal deposits

Coal Sector - Mineral Rights (contd.)

- Current legislation is deficient to varying degrees to encourage private sector investment
- significant problems relate to:
  - exemptions/privileges to PSEs
  - Discretionary powers of government
  - priority and exclusivity for mineral
  - geological information is not readily available to investors
  - coal blocks identified have not attracted investors

Coal Sector - Land Acquisition

- Forest (conversation) Act 1980
- Land acquisition Act 1994
- LA Act is available only
- CBA AD Act for coal bearing areas
- Land revenue code of some states
- Land acquisition procedures are prone to delay resulting in project getting delayed and/or abandoned
- Definition of land owners and land use is difficult
- Registration is neither sophisticated nor regularly maintained.

Coal Sector - Mining Operations

- A coal conservation policy and guidelines should be developed
- Regulations for opencast mining should be established
- In the longer term, a new Mines Act should be drafted to reflect modern approaches to health and safety in both opencast and underground mines

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Coal Sector - Labour Issues

- Regulatory Framework report focussed on following issues related to labour:
  - Employment rights - Incorporated in 8 pieces of legislation
  - Trade Union rights - TU Act 1926
  - Collective bargaining process
  - Terms and conditions of employment
  - Dispute resolution - ID Act 1947
  - Contract labour

Coal Sector - Collective Bargaining

- Joint bipartite committee for coal industry (JBCCI)
- Members from operating companies and 5 major trade unions
- Collective agreements on NCWA

In the present situation JBCCI fails to take into account varying abilities of individual subsidiaries to provide agreed benefits

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Coal Sector - Contract Labour Act

- Contract Labour (Regulation & Abolition Act) - 1970
  - it restricts use of contract labour in coal mines
  - these restrictions are damaging to existing producers and also for attracting new investment

Recommendations on Labour issues

- Law regarding employment rights to be codified
- Threshold for TU recognition to be raised
- Collective bargaining should pass to CIL subsidiaries
- Restrictions on employment of contract labour should abolished

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Coal Sector - Environment

Legislative framework:

- The Water (Prevention and Control of Pollution) Act 1974
- The Water (Prevention and Control of Pollution) Cess Act 1977
- The Air (Prevention and Control of Pollution) Act 1981
- The Environment (Protection) Act 1986
- The public Liability Insurance Act 1991

Coal Sector - Environment (contd.)

The environmental framework is reviewed specifically with respect to :

- Site and environmental clearance for mining projects
- Restoration of degraded land in mining areas
- Environmental protection during closure of mines
- Monitoring and enforcement of various laws for environmental protection

Recommendations - Environment

- Reclamation Trust Fund / Bond to be imposed
- Monitoring agencies should be strengthened
- Monetary penalties to be substantially raised
- Guidelines for mine closure to be formulated

Coal Sector - Forests

Legislative framework:

- Indian Forest Act, 1927
- Wildlife Protection Act 1972 (as amended up to 1991) with its many Rules
- Forest (Conservation) Act 1980
- Forest (Conservation) Rules 1981
- Environment (Protection) Act 1986 and Rules

Coal Sector - Forests (contd.)

Important topics analysed are :

- Diversion of Forest Land
  - Preparation and submisssion on proposals
  - Clearance process
- Compensatory Afforestation
- Forest Compensation (cost-benefit analysis)
- Schedule of lands

Recommendations - Forest Land

- States to identify suitable land for CA
- Forest compensation - clear guidelines by MoEF
- Partial and/or early reversion of forest land should be permitted
- A schedule of lands where mining will not be permitted should be prepared

Coal Sector - Resettlement & Rehabilitation

- R&R is a major challenge facing any investor
- No legislation at the central government level on R&R
- MP, Mahrashtra, Karnataka have enacted legislation for R&R
- Gujarat, Orissa have adopted formal ploicies
- CIL has adopted a comprehensive R&R policy
- Without exception, PAP want direct employment and is the most difficult issue

Coal Sector - Resettlement & Rehabilitation (contd.)

- Common problems, while implementing CIL R&R policy are
  - Definition of family
  - Unit of entitlement
  - Land for land
  - Landless people, share-croppers etc.
  - Resettlement site
  - Provision of compensation in lieu of land site
  - Community facilities

Oil and Gas Sector

Roadmap to Deregulation of the Indian Petroleum Industry

Till the mid-1970s, the Indian petroleum industry was operating as a free market with many of the multinational oil companies like Shell, Caltex, Esso, etc, having a significant presence. Nationalization of the oil industry resulted in the private players being bought out by the government. Since then, state owned 'public sector undertakings' (PSUs) have played a dominant role in this sector. In all PSUs, the government of India holds 51 per cent or more of the paid up share capital. However, now the government is in the process of deregulating the oil industry with a view to transforming it into a vibrant and globally competitive industry. Full deregulation of the petroleum industry is expected by April 2002. The following sections would give a holistic view of the factors that have triggered the process of deregulation and the initiatives taken towards opening up the upstream and the downstream sectors. There is a need to have a regulatory framework in place to ensure a smooth transition from a controlled petroleum sector to a free and competitive sector.

Deregulation: historical background

In the early 1950s, pricing was based on a system of Valued Stock Account (VSA). Under this system, the basic selling prices of major petroleum products were determined as the sum of f.o.b. Ras Tanura price, ocean freight, insurance, ocean loss, import duty, interest and other charges as well as 10% remuneration. However, the government decided to abandon this system of pricing as it was based on assumed costs rather than actual costs. Consequently, an Oil Price Enquiry Committee was set up in 1960, under the chairmanship of Mr. K R Damle. The committee recommended that ceiling selling prices for bulk refined products should follow the import parity principle.

By the 1970s, it was felt that the refining capacity of the country was adequate to meet the needs and thus the dependence on imports of petroleum products was less. It was also felt that the West Asian product prices, which were the basis for determining the import parity prices, did not necessarily reflect the cost pattern and operations of Indian refiners. The Administered Pricing Mechanism (APM) was introduced in 1977 and was later modified by the Oil

Cost Review Committee in 1984. The Oil Co-ordination Committee was set up in 1975 to manage Oil Pool Accounts and to co-ordinate supply and other matters of oil sector.

The APM essentially constituted a cost-plus pricing regime wherein costs were reimbursed as per standards laid out with respect to throughputs, yield patterns, fuel and loss, operating cost, capital employed, etc. Companies were allowed a 12% post-tax return on their net-worth and reimbursed their borrowing costs. The APM was aimed at ensuring continuous availability of petroleum products to consumers at fairly stable prices and crude to refiners, while ensuring the socio-economic objectives of the Government. The government plans to move from Administered Pricing Mechanism (APM) to Market Determined Pricing Mechanism (MDPM) by April 2002.

Initiatives prior to deregulation

Exploration bidding rounds to attract private investment started in 1979, but the early rounds were not successful. Nine rounds were offered between the period 1979 to 1995. The details of these rounds have been presented later in the discussion on upstream sector.

Private participation in the refining sector in the form of joint ventures with public sector was announced in 1986. Subsequently, MRPL was set up in 1987.

The marketing of lubricant-based stocks was allowed in 1992. The government had allowed parallel marketing of LPG (liquefied petroleum gas) and SKO (superior kerosene oil) in 1993, under which the import of these products were decanalised and private parties were allowed to import and market them at market determined prices.

The need for deregulation

There are various factors that have contributed significantly in initiating and carrying forward the process of reforms:

- Demand for oil and gas is expected to grow at the rate of 6-7% per annum in the near future. This demand can be met either by increasing domestic production or through imports. Domestic production can be increased if substantial domestic and foreign investments are made in this sector, hence requiring an investor-friendly environment.

- There have been serious unintended effects of the APM. Oil pricing has been divorced from underlying economic realities. The prices of politically sensitive products are not reflective of the economic costs of these products. Subsidies and cross-subsidies have resulted in a wide distortion of consumer prices and have led to a wasteful use of energy. The APM provided little incentive for improving productivity or efficiency as returns were guaranteed on the capital employed. Competition was stifled with marketing companies acting as mere distribution companies.
- Over the decades of the 1980s and 1990s, import of petroleum products soared ten-fold from over 2.2 million tonnes in 1975 to nearly 18 million tonnes in 1995. Given the high levels of import in the Indian economy, the APM, which insulated the country from global markets, had lost its utility. Further, it was estimated that during the Ninth Plan Period, an investment of about Rs 1,24,000 crores would be required to create the necessary infrastructure to meet the demand of petroleum products in the country. It was recognised that such a scale of investment was not possible by the Government or the public sector oil companies. Participation of private capital from both domestic and international sources was considered imperative. The APM, divorced from economic realities, was not attractive to private investors.

Steps towards deregulation

In 1995, the Ministry of Petroleum and Natural Gas (MoPN&G) set up the Oil Industry Restructuring Group ('R' Group) to come up with a time bound program for reforms in the petroleum sector. The phasing of reforms as envisaged by the R Group was as follows:

- Phase I (1996-98) : rationalisation of retention margin; deregulation of natural gas pricing; decanalisation of furnace oil and bitumen; partial deregulation of the marketing sector with freedom to appoint dealers and distributors; removal of the subsidy on HSD and reduction of the subsidy on kerosene, LPG and input for fertilizers
- Phase II (1998-2000) : pricing of indigenous crude on the basis of average FOB price of imported crudes; rationalization of royalty and cess; further deregulation of the marketing sector; further reduction of subsidy on kerosene, LPG and input for fertilizers
- Phase 3 (2000-02) : decanalisation of ATF, HSD, MS

As a follow up of the 'R' group recommendations, the Government had appointed an Expert Technical Group (ETG), an inter-ministerial committee, which was required to examine various scenarios reflecting the impact of different levels of duty structures on various sectors.

The ETG recommended a time-bound program of reforms to move towards a market driven pricing mechanism for petroleum products in the country. Following the ETG's recommendations, the Government[a] decided on several initiatives as summarised below:

1. The cost plus formula for pricing of indigenous crude was withdrawn by linking the price receivable by oil producers to a phased import parity scheme.
2. Retention pricing system for refineries was abolished and refinery gate prices were linked to import parity except for controlled products, namely, Motor Spirit (MS), High Speed Diesel (HSD), SKO, LPG and Aviation Turbine Fuel (ATF). Refinery gate prices for controlled products were fixed on an adjusted import parity basis.
3. Ex-storage point prices of HSD were fixed at import parity with immediate effect, while consumer prices of other controlled products were linked to a phased import parity. Prices of other petroleum products were decontrolled.
4. Imports and exports of all petroleum products except crude, natural gas liquids (NGL), ATF, MS and HSD were decanalised. Sourcing and imports of crude by private and joint sector refineries was allowed.
5. Phased rationalisation of duties on crude and petroleum products was announced.
6. Conditional marketing rights for transportation fuels, namely MS, HSD and ATF subject to investments of Rs 2000 crores in refining or a minimum crude production of 3 million tonnes per annum were announced.
7. Establishment of a regulatory framework to oversee the functioning of and enforcing a competitive framework in the hydrocarbons sector was suggested.

In addition, the refining sector was delicensed in 1998. Further, while naphtha exports were decanalised with effect from June 1998, Furnace Oil (FO) imports were decanalised under the provisions of the Export-Import policy in

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[a] Ministry of Petroleum & Natural Gas, Resolution dated 21st November, 1997

July 1998. Freight under-recoveries on HSD to the extent of 20% were passed on in the selling prices in January 1999.

However, it may be noted that HSD prices are not being fixed at import parity, despite the Government notification on the subject. Subsidies on HSD have, thus, inflated the deficit in the oil pool account. Administered HSD prices constitute a major distortion of the reform agenda.

In significant moves towards deregulation, the Government recently announced decontrol of ATF prices and the disinvestment in IBP with bidders being required to commit themselves to an investment of Rs. 2,000 crore in exploration and marketing, refining, pipelines or terminals. This is a departure from the existing norm as per which marketing rights for transport fuels can be given to only those private sector companies which own and operate refineries with an investment of at least Rs 2,000 crore or to oil exploration and production companies producing at least 3 million tonnes of crude annually.

But progress towards rationalization of duties on crude and petroleum products has not been in line with the milestones for deregulation. Duty on crude oil and transportation fuels was revised in September 2000 in the wake of spiralling international prices. With stabilization of international crude oil prices, the duty on crude was brought down from 15% to 10% while that on transportation fuels from 25% to 20%.

In his speech presenting Budget 2001/02, though the Finance Minister indicated that total price decontrol of petroleum products would be completed by April 2002. In this budget some petroleum products were taxed more heavily. There was a roll-back of reduction in excise duty on HSD from 16% to 12% and exemption of Special Excise Duty of 16% on MS proposed in September. Also a 5% duty was introduced for SKO sales under the pubic distribution scheme. The net result is that the current duty structure remains at variance with the approved structure. The variance between actual and approved duties is presented in Table 1.

Table 1. Gaps in rationalization of duties to Government approved levels: 2001/02

Product	*Approved by Government*	*Actual*
Customs duty		
Crude	0 - 5	10
HSD	15	20*
MS	15	20
ATF	15	20
LPG	10	10
LNG	0	5
FO/LSHS	10	25
Naphtha/NGL	5	5
Kerosene	0	5
Kerosene (PMS)		35
Others	15	25
Excise duty		
HSD	15	16*
MS	165	16+16
LPG	10	8
Kerosene	10	8

* Additional excise of Re 1/litre of HSD

Issues in the upstream sector

India has total recoverable reserves of 658 million tonnes of crude oil and 628 billion cubic metres of natural gas. India has a very large sedimentary area of about 3.14 million square km comprising 26 sedimentary basins. Out of these, only six basins have been explored for oil and gas. Approximately 70% of the sedimentary area lies unexplored. Only 16% is well explored and the rest is poorly explored. Till recently, exploration activity was largely in the hands of the two National Oil Companies - Oil and Natural Gas Corporation Ltd. (ONGC) and Oil India Limited (Oil). ONGC and OIL have a share of about 88% of the country's present oil and gas production. Private/JV consortia account for only 12% of oil and gas production.

Exploration bidding rounds to attract private investment started in 1979, but the early rounds were not successful. The first four rounds were spaced over a period of twelve years (1979-91). The next five rounds came in two years (1994-95) and succeeded in generating some interest in the international oil industry. To increase this interest, the government decided to award some small and medium sized fields for development in the private and joint sectors respectively. An innovation was also introduced in the ninth round - known as the JV (joint venture) round – to reduce the risk for the private investors by associating ONGC/OIL as partners in these exploration ventures. The total investment by the private sector in these is estimated to be in excess of $ 2 billion.

The details of blocks advertised before the launch of the New Exploration Licensing Policy (NELP) and the bids received in the various rounds are presented in Table 2 below.

Table 2 Exploration blocks offered and bids received

Round	Year	Blocks offered	Bids received
I	1979	32	4
II	1982	50	nil
III	1986	27	13
IV	1991	72	24
V	1993	45	15
VI	1994	46	20
VII	1994	45	12
VIII	1994	34	38
JV	1995	34	22

ew Exploration Licensing Policy

The Government of India has stepped up its initiative of enticing private investment into the oil sector. The most significant milestone in this regard has been the notification of the New Exploration Licensing Policy (NELP) announced in 1997-98, with two main objectives:

- Attracting private sector and foreign investment in exploration and production.
- To gather as much data as possible and map the sedimentary area accurately.

With it, the Government hopes to eliminate the country's burgeoning demand-supply differential and the resultant expensive reliance on import of crude and petroproducts. This series of new, attractive fiscal and contractual terms are designed to attract international operators to the Indian oil sector. Oil companies from the private and the public sector will be treated at par and all new acreage acquired will be given market-driven price of crude oil and natural gas produced. This will hopefully enable the Government to award acreage to the company with the best work programme and fiscal terms. The salient features of NELP are as follows:

- National Oil Companies to compete for acreage.
- No payment of signature, discovery or production bonus.
- No minimum expenditure commitment during the exploration period.
- No mandatory state participation/carried interest by NOCs.
- Freedom to sell crude oil and natural gas in domestic market at market related prices.
- No cess on crude oil production.
- Royalty payment for crude oil on ad valorem basis
  - 12.5% for onland areas
  - 10% for offshore areas
- Royalty on deep water areas (beyond 400m bathymetry)
  - 5% for first seven years after commencement of commercial production
- Infrastructure status: 7 year tax holiday from commencement of production

NELP - I

In the first round of NELP in January 1999, the Government of India invited bids for 48 exploration blocks, comprising 26 offshore blocks, 10 onland blocks and 12 deep offshore blocks. Of the 48 blocks offered, the Ministry of Petroleum and Natural Gas approved the award of 25 blocks to domestic and foreign companies in January 2000. The government signed the Production Sharing Contracts (PSCs) for 25 oil blocks in April 2000. Of these 25 blocks, 3 blocks were awarded earlier. The participation in NELP I bidding process indicates that Indian and foreign private companies as well as the NOCs have responded positively. Details of the blocks awarded and PSCs signed are presented in Table 3. Total area covered in these 25 blocks is 231,870 square km. Out of the 15 bids ONGC had submitted, it bagged the contracts for 8 blocks.

Table 3. Blocks awarded and PSCs signed under NELP-I

Sl No.	Basin	Area (sq.km.)	PSC signed with
Onland Blocks			
1	Arunachal Pradesh*	300	Geoenpro-Geopetrol-Enpro India
2	Ganga Valley	36750	ONGC-IOC
Deep Water Blocks			
3	Krishna Godawari (Offshore)	10810	RIL-NIKO
4	Krishna Godawari (Offshore)	9800	Caim
5	Krishna Godawari (Offshore)	7645	RIL-NIKO
6	Krishna Godawari (Offshore)	9940	ONGC
7	Krishna Godawari (Offshore)	8980	ONGC
8	Mahanadi	9605	RIL-NIKO
9	Mahanadi	10005	ONGC
Shallow Water Blocks			
10	Cauvery	4940	Mosbacher-Energy Equity-HOEC
11	Cauvery	5215	OIL
12	Gujarat - Kutch	1465	RIL-NIKO
13	Krishna Godawari	4485	ONGC
14	Krishna Godawari	4790	RIL-NIKO
15	Krishna Godawari	2460	RIL-NIKO
16	Krishna Godawari	4020	RIL-NIKO
17	Kerala - Konkan	19450	RIL-NIKO
18	Kerala - Konkan	15910	ONGC
19	Mumbai	5270	RIL-NIKO
20	Mumbai	5740	RIL-NIKO
21	Mumbai	18870	ONGC-IOC
22	Mahanadi	5420	ONGC-GAIL
23	North East Coast (Offshore)	14535	RIL-NIKO
24	North East Coast (Offshore)	10425	OAO-Gazprom-GAIL
25	Saurashtra	5040	RIL-NIKO

** PSC could not be concluded*

NELP - II

The government has offered 25 exploration blocks under NELP-II in December 2000. These include 9 onland blocks, 8 offshore blocks and 8 deepwater blocks. Of the 25 blocks offered, 23 blocks have been awarded by the Government and Production Sharing Contracts would be signed. Table 4 presents the details of blocks awarded and the successful bidders in NELP II. Total area covered in these 23 blocks is 268,344 square km.

Table 4. Blocks awarded under NELP-II

Sl No.	Basin	Area (sq.km.)	Successful bidder
Onland Blocks			
1	Upper Assam	6215	RIL-HEPI
2	Cambay	1424	GSPC.Ltd.,GAIL-JTI
3	Cambay	419	Niko Resources Ltd.
4	Ganga Valley	23500	ONGC-IOC
5	Mahanadi	7900	OIL-ONGC-IOC-GAIL
6	Rajasthan	2535	OIL
7	Bengal	12505	ONGC-IOC
Shallow Water Blocks			
8	Cauvery	5920	ONGC
9	Cauvery	3530	ONGC
10	Gujarat - Saurashtra	8841	RIL-HEPI
11	Kerala - Konkan	16125	ONGC
12	Mumbai	18414	ONGC-IOC-GSPC
13	Mahanadi	6730	ONGC
14	Mahanadi	8330	ONGC-IOC-GAIL-OIL
15	Bengal	6700	ONGC-IOC
Deep Water Blocks			
16	Gujarat - Saurashtra	13937	ONGC
17	Gujarat - Saurashtra	14825	ONGC-GAIL
18	Kerala - Konkan	18113	RIL-HEPI
19	Kerala - Konkan	20998	ONGC-GAIL
20	Kerala - Konkan	14889	RIL-HEPI
21	Kerala - Konkan	26149	ONGC
22	Mumbai	11239	ONGC-IOC
23	Mumbai	19106	ONGC-IOC-GAIL-OIL-GSPC

The government is planning to invite bids under NELP III by the end of this year. The primary objective of NELP was to attract foreign investment in exploration and production. However, the responses to NELP I and II indicate that most of the foreign majors, including Exxon-Mobil, Total Fina and Shell, have stayed out of the bidding process under both rounds.

Policy for encouraging LNG imports

The burgeoning gap between demand and supply of natural gas has impelled the Government to promote the import of natural gas. Gas demand projections as given by Hydrocarbon Vision 2025 are presented in Table 5. In 1996, Petronet LNG was formed by the Government to facilitate imports of LNG. This company is promoted by four public sector hydrocarbon majors – IOC, BPCL, ONGC and GAIL. The LNG projects have been proposed by companies like Shell at Hazira, CMC Energy/Unocal/Grasim at Ennore, IOC/Petronas at Kakinada, Tata/Totalfina/GAIL at Mumbai and British Gas at Pipavav.

Table 5. Gas demand projections (MMSCMD)

Year	*Demand*
1999-2000	110
2001-2002	151
2006-2007	231
2011-2012	313
2025-2026	391

The government is considering the formulation of a comprehensive policy on LNG import. The policy has been pending since last one year. It is likely to be finalised shortly with the Centre moving a cabinet note for the approval on specific issues of LNG policy, nature and scope of regulation in the sector, location and size of LNG terminals, role of Indian shipping companies in LNG transportation and rationalisation of taxes and duties. Till the time a proper regulatory mechanism is in place, an inter-ministerial committee of secretaries would regulate the LNG sector. Gas prices would best be left to the market forces.

LNG shipping policy

India is expected to become a major importer of LNG in the coming few years. LNG terminals are being established in locations like Dahej, Kochi, Dabhol, Ennore and Pipavav. The LNG shipping policy of the government requires a minimum 26% shareholding by an Indian company in any venture carrying LNG to India and this has to be maintained throughout the period of the contract. At present, the policy allows only fob imports of LNG. This would, however, be reviewed after seven years. The policy requires that there should be a transfer of technology to the Indian shipping partner so that within five years from the registration of the vessel, it would be managed, maintained and operated by Indian crew and personnel. Further, it encourages the registration of the LNG vessel under the Indian flag. Till date, only the flagship carrier Shipping Corporation of India has ventured into LNG shipping. Finally, the government is looking at enabling a zero level of taxation for a specified number of years for Indian shipping companies in the LNG business.

Competitiveness of LNG in power generation

The viability of LNG as a fuel for power generation needs to be explored. The analysis of viability of LNG is specific to timing and location. LNG prices are linked to crude prices. Hence, fluctuations in crude prices would have a bearing on LNG prices, which would then determine the cost of power generated. In addition, gas in India has to compete not only with coal but there will be substantial gas-on-gas competition. LNG has to compete with other imported gas (piped gas), as well as domestic gas.

Industry level impacts of deregulation: the downstream sector

The Indian petroleum industry is expected to be fully deregulated in April 2002 and with this the operating environment in the industry is likely to witness sweeping changes. Some of these are described below.

Industry structure: more players, intense competition

Already some of the petroleum product segments of the downstream sector are freed from governmental controls. With the government opening up the petroleum industry, the marketing of transportation fuels would also witness private sector participation.

When the Indian lubricants market was decontrolled in 1993 to parallel marketing, there were 20 new entrants who captured about 12% of the market in just five years, eating into the market shares of established players like IOC and BPCL. The market also saw a spate of joint ventures such as the Indo Mobil between Mobil and IOC to blend, package, distribute and market Mobil brand lubricants throughout the country.

Similar restructuring of the industry may be expected with the decontrol of transportation fuels – while the increase in number of new players may not be as high as in the case of lubes, primarily on account of the conditional marketing rights, the degree of competition in this sector would be more severe.

Sourcing of crude oil

Till recently, all PSU refineries had to source crude through IOC, which was the sole canalising agent. Only joint sector and private refineries had freedom in crude sourcing and imports. On March 14 this year, the Government extended this freedom to all PSU refineries. The move was welcomed by the industry as imports could now be tailored to suit the exact requirements of a particular refinery. All companies would now need to be prepared to chalk out their optimal crude sourcing patterns, taking into consideration prices (f.o.b price as well as freight component) as well as yield patterns for various domestic and imported crudes.

Domestic crude pricing and sourcing

Post deregulation, domestic oil producers are likely to price their crude at full import parity prices. In addition, the existing system of allocation of domestic crude is likely to be discontinued. Refiners would have to get into commercial agreements with domestic producers like ONGC and OIL to source domestic crude for their refineries. Reportedly, several PSUs and even private players like Reliance Petroleum Ltd are considering long-term commercial agreements for crude supplies from ONGC.

Refining – capacity utilisation and yield patterns

Under the current system, production of public sector refineries is co-ordinated by the OCC keeping in mind regional product demand patterns. Post deregulation, refineries would be free to determine their yield patterns and capacity utilisation levels in accordance with the demand and realisations for petroleum products.

Product pricing

The Government currently administers ex-storage point prices for controlled products. Post deregulation, all controls on pricing of products would be lifted. However, reduced subsidies on SKO and LPG would continue and these would get transferred to the fiscal budget.

In such a scenario, pricing may be expected to be set on the import parity principle. However, several factors are likely to impede the setting of prices at import parity levels – specifically, the existence of surplus in certain products; the impact of competitive forces; problems relating to access to and tariff-setting for pipelines and other infrastructure. Details on likely pricing scenarios in the post-deregulation era are given in a following section.

Product distribution

Under the present system, distribution of controlled products is co-ordinated by the OCC. Its monthly Supply Plan for controlled products includes specifications on product movements and mode, deliveries and receipts at terminals and depots and pipeline throughputs. Post deregulation, product distribution would have to be organised separately by each marketing company.

In such a scenario, access to marketing infrastructure becomes critical. Transportation costs comprise a significant portion of consumer prices of petroleum products. Product movement by pipelines offers the least cost option for transportation and requires much less energy as compared to other modes of transportation.

The issue of open access to pipelines has been discussed by several groups/forums in the industry – the Expert Technical Group, the Group on India Hydrocarbon Vision 2025, etc. It has been opined that pipelines are natural monopolies and should be declared as "common carriers" by the Government and the use of facilities for existing pipelines could perhaps be determined through negotiations amongst concerned parties and facilitated by the proposed regulator for the sector. There is no concensus, however, on access to and tarriffs for storage and marketing. factilities.Tariffs for pipeline access have been laid out by the ETG for 1999/00 (Table 6) with the suggestion that these be escalated annually by 80% of the annual inflation in the wholesale price index. However, this proposal is still under consideration by the government.

Table 6. ETG-recommended product pipeline tariffs for 1999/00 (Rs/MT/Km)

Product pipelines	Up to 300 kms	Beyond 300 kms
Existing pipelines	0.81	0.77
New pipelines commissioned after 1 April 1998	1.20	1.13

Market shares and marketing efforts

Under the present system companies engage in product exchange and each refinery caters to full industry[1] volumes. In addition, products are often cross-hauled, with expenses being reimbursed from the oil pool.

Post deregulation, with each refinery seeking to minimize its costs (including distribution costs), refineries are likely to concentrate their marketing efforts in the most lucrative depots – i.e. depots where positioning costs are the lowest and competition is likely to position products at heavy discounts. It is extremely difficult to predict likely market shares in a situation that would be characterised by uncertainties with companies vying with each other for enhanced shares.

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[1] Total requirements of IOC, HPC, BPC and IBP

Retail operations

Under the present system, the location and size of facilities at large volume consumers is subject to Government approvals. In addition, product dealers and retailers are selected through appointed bodies. In a deregulated environment, it is expected that PSU marketeers would have the freedom to decide on their retail networks.

The threat of competitive takeovers of retail outlets in a deregulated scenario is imminent . Recent trends indicate attempts at consolidation of retail networks, by increasing the proportion of company-owned retail outlets. For instance, IOC has steadily increased the share of company-owned & company-operated retail outlets to 34% of its over 7500 sales points and has announced plans for increasing this share to 50% in the next two years. The race for stakes in the public sector oil marketing company IBP is also indicative of the realisation that a stronger retail network could provide the cutting edge in a fiercely competitive environment.

Internationally, chains of convenience stores add to retail margins of transportation fuels. In the USA, it is estimated that about 60% of gasoline sales are through convenience stores. Indian companies are also investing large sums in upgrading their strategic outlets to add value-added services like restaurants, automatic teller machines, shopping convenios and cyber cafes. BPC is said to be targetting 10% non-fuel revenues in the next three years.

Regulatory Framework

One of the key issues in a deregulated environment would be that of ensuring a level playing field for all players. At the same time, consumer interests with regard to availability of products at competitive prices also need to be safeguarded. In general, competitive forces are considered to be self-regulating. Regulatory intervention, though essential for some issues, would thus be restricted to selected areas. Details on the regulatory framework are discussed in a subsequent section.

Pricing scenarios for petroleum products

As mentioned earlier, it may be expected that prices in the domestic markets would be based on the import parity pricing principle. These prices would, however, be impacted by competitive forces with the most efficient player (equipped with lower costs that could translate into discounting capability) setting the price in each market. For some products, like MS, where surplus volumes may exist, these surpluses may be valued at export parity prices. Of course, exports would be subject to demand in international markets, particularly the Asia Pacific region.

Import parity prices

In the deregulated scenario, the present system of administered uniform ex-storage point prices for controlled products is likely to get replaced by one in which companies would offer products at different rates in different markets depending upon the extent of competition prevailing in that market. In general, market prices would reflect import parity prices, i.e., landed cost of a product at the nearest port, the least-cost freight from the port to the market and a reasonable margin to cover selling/distribution expenses and profits.

International prices

International prices significantly influence pricing in the import parity regime. International prices are highly volatile. Table 7 indicates that variations in prices across the year 2000/01 were upto $80/MT. In the absence of pool accounts, such fluctuations would impact on domestic prices. Spreads between crude and product prices change rapidly, affecting refining margins.

Table 7. International product prices: Fob Middle East Gulf ($/MT)

Product	*Quarter Averages: 2000-01*				*Annual Average*
	Q1: Apr - Jun	*Q2: Jul - Sep*	*Q3: Oct - Dec*	*Q4: Jan - Mar*	*2000-01*
SKO	224	288	289	207	252
HSD	203	260	241	180	221
MS	258	303	257	235	263
ATF	224	289	289	208	253
FO	147	143	140	109	135
Naphtha	232	262	244	213	238
LPG	276	296	335	324	308

Importer's margin

An assessment of importer's margin is important because the other elements in import parity prices reflect actual costs. TERI estimates indicate that importers margins (to cover marketing costs and ensure reasonable profits) may be set at around $3/bl for the purpose of estimation of import parity prices. This estimate is based on several sources: surveys among key players importing decontrolled products in India as well as secondary data on companies in Thailand[2] and USA[3].

Import parity price setting for HSD at Ambala depot in Haryana is presented in Annexure 1. It illustrates how this principle may be applied. The port nearest to Ambala is Kandla, Gujarat. Annexure 1 shows the import parity price build up for HSD at Kandla port and then worked forward to Ambala.

Impact of competitive forces on prices

While it may generally be expected that with deregulation, prices of petroleum products would move towards international prices, some factors, competitive forces in particular, may impede the setting of prices at import parity. Given that there is little indication of brand preference in most petroleum products, competition is likely to be manifested in price wars. Thus price-setting would be crucial in capturing and retaining customers. The price that would prevail in any market is likely to be the lowest offered by any player, with all other players following suit to avoid losing out on market share.

In the identification of the most efficient player, an assessment of relative advantages of competitors is imperative. These advantages may flow either from differences in cost structures or from other policy parameters such as fiscal incentives. Such advantages would translate into discounting capabilities in the marketplace. These discounting capabilities would, however, differ vis a vis each refinery and would be depot specific.

The single most important point of comparison would be crude costs, which constitute over 90-95% of refining costs. Fiscal incentives could be another advantage. A review of the audited financial results of RPL indicates that deferred sales tax liability for 2000/01 works out to be Rs 960.52 crores. Netting out Rs 100.44 crores set aside by the company for defeasing this liability, benefit accruing to RPL is estimated at Rs 860.08 crores, which translates to a sizeable average benefit of about $ 1.02/bl for the year 2000/01.

In summary, each refinery would, therefore, compare itself with the most efficient player and then estimate this competitor's advantage using its relative refining efficiency (reflected in direct variable refining costs, primarily crude costs) net of its positioning costs (i.e. the competitor's cost of positioning products in markets located within its economic zone) plus any other advantage that the competitor may have out of policy incentives extended.

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[2] National Energy Policy Office, Thailand

[3] Source: Energy Information Administration, Financial Reporting System - based on data for select US companies

Other impacts of competitive forces: cuts in market shares

In addition to price wars, competitors may also engage in aggressive marketing to capture market shares. This is particularly true of direct trade where marketing investments required may be lower than that for retail operations. In this regard, refineries would particularly have to be wary of importers capturing coastal customers or of consumers directly importing their requirements. As a result refineries servicing coastal markets are particularly threatened in respect of their direct sales. Such aggression may also be visible in the retail segment with competitors trying to buy out retail outlets.

Strategies likely to adopted to combat competition in free markets

Dealing with surplus products

An analysis of the likely demand-supply situation in 2002/03 indicates that petroleum products, such as MS, are likely to be in surplus. In attempting to analyse how companies are likely to react in such a situation, the possibility of exports has been explored. Exports to East Asia – the most likely destination – are, however, likely to be difficult on account of a supply overhang in the region (Figure 1).

In such a situation, throughput cuts are inevitable. Here, it may be worthwhile to mention that refining capacity utilisation in the Asia-Pacific region has hovered between 82% - 88% over the last decade, while APM influenced over-utilisation of refining capacity in India. Post-deregulation, with product offtake from refineries not guaranteed, companies would have to decide on throughput levels that maximise margins for them. With reduction in throughputs, there would be unmet demand for some products in certain markets which would have to be met through imports.

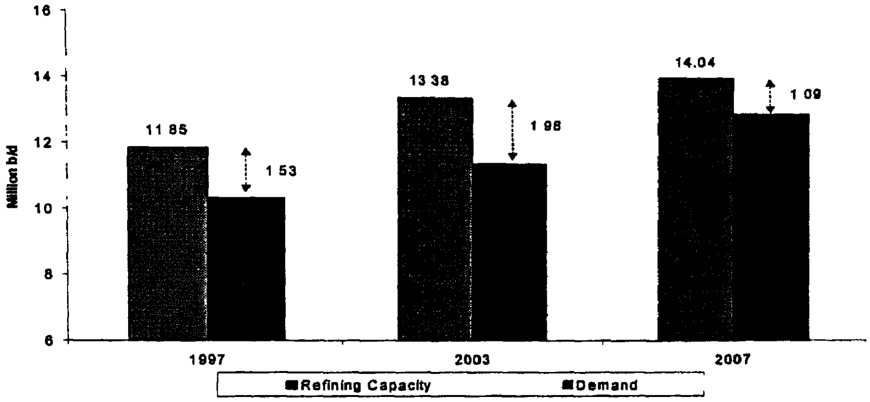

Figure 1 Oil refining capacity and demand in East Asia

Marketing strategies : product exchange or regional focus

As mentioned earlier, in their drive to reduce distribution costs, refineries would minimise movements of products outside their "economic" evacuation zones. As a result, two kinds of strategies are likely to emerge – either companies would enter into product exchange agreements with competitors or would aggressively capture markets to emerge as strong regional players. The former is more likely given that it entails lower costs than in aggressive marketing and would therefore maximise margins for the industry as a whole.

Optimising raw material costs

As indicated earlier, crude procurement would constitute a key element in determining relative cost advantage among various players.. Most Indian refineries are found to use a mix of Middle Eastern, West African and domestic crudes. In the post-deregulation scenario refineries would have to explore the techno-economic feasibility of using a variety of crudes. Industry reports indicate that large discounts are available on several crudes such as the Venezuelan Mesa and the Mexican Maya crudes

Organisation flexibility and dynamism

In the deregulated scenario, companies are expected to fiercely compete with each other in the marketplace. Clearly cost cutting, concerted marketing efforts and quick decision-making could provide the cutting edge. The market is likely to be very dynamic and a great deal of volatility is imminent, at least in the short term. Over the longer term, industry players would find it beneficial to increase administrative flexibility and dynamism to cope with the uncertainty and unpredictability that are characteristic of free markets.

Regulatory Framework

Need for a regulatory authority

The process of deregulation aims at fostering a competitive environment in an industry, thereby assuring consumers the availability of quality products at competitive prices. Government decisions so far – private participation in upstream, parallel marketing, delicensing of refineries, decanalisation of crude and petroleum products, price decontrol, etc.– all target nurturing competition in the oil industry. However, there remain areas where competition is likely to be ineffective, especially in areas where there have been virtual state monopolies in the past. The efficacy of market forces alone in such situations is questionable.

In such a scenario, there emerges a need of simulating the effects of competition through a combination of controls and standards. Such initiatives come under the purview of a regulatory authority. For the Indian hydrocarbons sector, two key issues emerge,

Assure a level playing field for all players
Protect consumer interests with respect to availability of petroleum products at fair prices

Level playing field
Marketing of transportation fuels at present is reserved for public sector oil companies only. Post deregulation, subject to eligibility criteria, private concerns would be allowed to venture into retailing of transportation fuels. However, new entrants are likely to face stiff competition from PSUs given their established distribution infrastructure – pipelines, storage depots, hydrants, etc.

Private players argue that the rationale for deregulation has been promotion of competition in markets to enhance quality and service levels. While instituting a high level of competition would require substantial time, the process can be expedited by providing open access to markets and consumers. Accordingly, they have expressed the need for access to existing distribution infrastructure such as pipelines, storage installations, depots, hydrant systems at airfield installations, etc. If access be denied to them, duplication of such facilities would only lead to an increase in product prices at the consumer end.

In contrast, the public sector companies argue that, post deregulation, the downstream petroleum sector is akin to any other business activity. A new entrant in any business, is at a disadvantage to an established player with his facilities in place. New entrants capture markets on the basis of their competitive advantage - be it service, technology, quality or marketing skills. As in any other business, an existing player may or may not consider to lease/hire out the use of its facilities to other market players.

The above mentioned clearly brings out the wide difference in views on the subject. Post deregulation, thus, there emerges a need for an expert body (regulator) to mull over such issues and take appropriate steps to assure a level playing field for all stakeholders.

Consumer interests

In a deregulated environment, both logistics and pricing, would be outside the purview of Government control. Oil companies would decide themselves, where they wish to market their products and what prices. In such a scenario, there are possibilities that companies may suspend operations in markets which are not lucrative enough, especially the far flung areas. There, thus, emerges a need, to institute a mechanism to assure access to and availability of petroleum products.

At the same time, in the absence of administered pricing, possibilities of collusive pricing by marketeers also emerge. Given the widespread usage of petroleum products, rational petroleum prices are crucial for an economy. Sharp or undue increases can easily lead to inflationary pressures. Further, given that energy constitutes the basic input for any industrial activity, prices of petroleum products affect competitiveness of the whole manufacturing/industrial sector.

International experience in regulatory systems

The hydrocarbons industry can be broadly classified into two categories – upstream activities related to exploration and production of crude and natural gas; and downstream activities encompassing refining and marketing of petroleum products and gas. A review of regulatory experiences in these two categories is summarised below:

Upstream

The world over, Governments tend to retain control over exploration and development of mineral resources. Governments, being owners of these resources, are charged with the responsibility of ensuring optimal utilisation of a nation's mineral wealth. A survey of upstream regulation in US, UK and Norway revealed that upstream regulation entails,

a) Promoting exploration of oil and gas resources
b) Supervision to ensure that licensees manage resources in an efficient and prudent manner
c) Ensuring environmental protection and impact mitigation of upstream activities

These responsibilities fall under the purview of the Department of Interior in the US, the Department of Trade & Industry in the UK and the Ministry of Petroleum & Energy in the Norway. Government control in upstream regulation, is clearly evident from the above mentioned.

In fact, a similar situation is also witnessed in developing economies,

- Argentina : Energy Secretariat under the **Ministry of Economy**
- Mexico: Absolute monopoly of Pemex under the **Ministry of Energy**
- Thailand: Department of Mineral Resources under the **Ministry of Industry**
- Venezuela: Director General Hydrocarbons under the **Ministry of Mines & Energy**

The above examples clearly illustrate that Governments, being rightfully concerned about exploitation of a nation's mineral resources, tend to retain control over regulatory issues in the upstream sector.

Downstream

A review of regulatory systems elsewhere in the world indicates the following role for a regulatory authority in the downstream sector,

- Fostering competitive markets
- Assuring access to quality products/services at reasonable prices
- Consideration of environmental impacts of energy projects

One of the most important functions of regulatory agencies, be it the Federal Energy Regulatory Commission (FERC) in the USA or the National Energy Board (NEB) in Canada, is that related to regulating transmission of oil and gas via pipelines and setting tolls & tariffs for fair access to pipeline systems. Agencies world over recognise that pipelines are natural monopolies. Ensuring competitive markets, thus, requires measures and systems that do not offer any single player undue competitive advantage on account of access to/ownership of pipeline networks.

Typically such agencies are independent authorities, created through enabling legislation, which confers powers from existing legislation to the new authority. The FERC, for instance, was created through the Department of Energy Organisation Act and it draws powers from Acts like the Federal Powers Act, Natural Gas Act, Natural Gas Policy Act, etc. Likewise the Gas and Electricity Markets Authority in the UK draws on powers from The Gas Act, The Electricity Act, and The Competition Commission.

One key aspect which stands out in downstream regulatory systems is that a ***single agency*** regulates on matters related to ***both oil and gas***. In fact, both FERC and the NEB regulate electricity transmission as well in addition to transmission of oil and gas via pipelines.

gulatory Framework for the Indian Hydrocarbons Sector

Upstream

In light of the above mentioned international experience in upstream regulation, it appears that there is no adequate justification for a separate regulatory authority for the upstream sector. The regulation of oilfields and the development of mineral oil resources of the country presently is as per the Oilfields (Regulation and Development) Act, 1948. In addition the Government is assisted by the Directorate General Hydrocarbons (DGH).

Downstream

Again, in line with international experience and on account of the commonality of regulatory functions in downstream oil and gas, viz., tariff setting for common carrier pipelines, assurance of level playing field, assuring availability of gas/petroleum products at competitive prices, etc., ***a single authority is preferable.***

As is the case in other countries, the new regulatory authority should be created through appropriate legislation. Creation of this authority by an Act of

Parliament would also ensure independence of the regulator's office. The regulatory body should be independent of the Government on account of the fact, that the Government would also be a regulated entity due to its stake in public sector oil companies. Independence is also imperative to assure confidence to private and foreign investors.

Need for an interim authority

While it is imperative that the regulatory authority should be created through appropriate legislation, prior legislative experience indicates that enactment of new legislation can take considerable time. Meanwhile full deregulation of the hydrocarbons sector is expected by the April 2002. The regulatory body should be instituted well before full deregulation of the sector. Given the limited time frame, the possibility of positioning a regulator under the existing Acts/Rules should be explored. This approach offers the added advantage of providing the Government actual regulatory experience in the hydrocarbons sector to frame appropriate legislation.

It may be noted that a similar approach was adopted while setting up the Securities and Exchange Board of India (SEBI) and the Insurance Regulatory and Development Authority (IRDA). SEBI was constituted by the Government as a non-statutory body in 1988 to promote the developments of the security markets and to provide adequate investor protection. SEBI was given statutory recognition by an ordinance promulgated in March 1992. The ordinance was then replaced by The Securities and Exchange Board of India Act, 1992 after obtaining adequate experience in regulation of financial markets.

Likewise, the Government instituted an Interim Insurance Regulatory Authority in January, 1996 through a Government Resolution. The interim body was set up, under the Ministry of Finance, to evolve a format for effective control over the insurance industry, deal with all matters relating to promotion and orderly growth of the insurance market, propose comprehensive legislation for an autonomous IRA conceptually similar to the SEBI and carry out such other non-statutory functions as may be delegated by the Government. IRDA in its present form was finally set up after three years through the Insurance Regulatory and Development Act, 1999.

Thus, drawing from prior experience and given the widespread implications of developments in the hydrocarbons sector, it is suggested that an interim regulatory authority be constituted to address imminent regulatory issues in a deregulated environment. The interim authority could subsequently undertake the task of drafting comprehensive legislation for providing statutory support to the same.

Functions of the proposed authority

Key functions of the proposed regulatory authority may be as below:

1. To ensure a level playing field for all operators: The regulator would have to balance consumer interests with those of investors and at the same time ensure a level playing field for all investors.
2. To regulate tariffs for pipelines used as common carrier: Since pipelines are natural monopolies in areas that they serve, in order to ensure a level playing field, the regulator would have to assess tariffs for use of common carrier pipelines and associated facilities.
3. To ensure transparency in tariff setting: Tariff setting is critical for a firm's profitability and consumer prices at the retail end. The regulator will have to develop publicly known mechanisms for tariff setting.
4. To analyse trends in market prices to prevent cartelisation: One of the key functions of the regulator would be to protect consumer interests. In order to do so, the regulator would have to keep a track of changes in market prices and prevent the formation of cartels.
5. To monitor global developments of the hydrocarbons sector: In order to perform its various roles, the regulator's office would have to be a repository of information on the hydrocarbons sector pertaining to sales, production, availability, import/exports, demand estimates, etc.
6. To implement Government policies: Policy development would continue to rest with the Government. The regulator would have to implement prevailing policies for the hydrocarbons sector.
7. To secure involvement of voluntary agencies and user associations to implement consumer protection measures: The role essentially entails promotional efforts at increasing consumer awareness with regards to product quality.
8. To ensure supply of products to far-flung areas: The regulator would have to devise an appropriate scheme to administer freight subsidy to far-flung areas.
9. To intervene in crisis situations/natural calamities/wars: While most organisation would have their own contingency measures to deal with crisis situations, the regulator can provide overall direction and guidance.

10. To assist in planning and development of the hydrocarbons sector: The regulator would have the added responsibility of promoting the healthy growth of the hydrocarbons sector.

Annexure 1. Indicative Import Parity Price of HSD: Ambala

Element	*Unit*	*Value*
Fob	$/MT	221
Fob[1]	Rs/MT	10165
Load Port Charges @ 1$/MT	Rs/MT	46
Freight (25-45 TMT)	Rs/MT	387
Cost & freight	Rs/MT	10598
Insurance @0.3%	Rs/MT	32
Ocean Loss @ 0.3%	Rs/MT	32
Cif	Rs/MT	10661
LC Charges @ 0.3% of Cif	Rs/MT	32
Landing charges	Rs/MT	55
Customs duty @ 15%	Rs/MT	1607
CVD @ 15%	Rs/MT	1849
Cost including Duty	Rs/MT	14204
Terminalling charges	Rs/MT	182
Landed Cost	Rs/MT	14386
Financing charges	Rs/MT	106
Marketing margin [2]	Rs/MT	1050
Import Parity Price: Kandla	Rs/MT	15542
Least cost movement from Kandla to Ambala	Rs/MT	1125
Import Parity Price: Ambala[3]	Rs/MT	16667

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1. Average Fob MidEast Gulf prices over the period Apr'2000 - Mar'2001
2. Based on surveys in India and secondary data on companies in USA and Thailand (details above)
3. There are three possible modes of movement: the Kandla-Bhatinda Pipeline (KBPL), rail movement or by road through tanker trucks. Movement by KBPL would have lowest costs at Rs 1,125/MT

IAS Officers training on Energy Sector Reforms

Presentation on

Restructuring of the Oil & Gas Sectors - an update

by

R K Batra
Distinguished Fellow
TERI

October 19, 2001

APM REGIME

1. All ex-refinery prices & selling prices controlled*
2. Fixed return to oil companies based on networth & borrowings
3. Pool Accounts maintained by OCC
4. Refinery throughput, yield pattern and distribution on integrated optimized all-India basis. "Pooling" of refinery production and imports
5. Canalization of crude oil and product imports through IOC
6. Marketing share of oil companies based on a formula
7. Appointment of dealers and distributors by Oil Industry Selection Boards
8. PIB approval for even moderate investment decisions
9. Surcharges on MS/ATF subsidize SK/LPG
10. MoP&NG & OCC the regulators

* ONGC/OIL/GAIL paid less than import parity prices for crude oil and gas.

OIL & GAS COYS IN INDIA - 2000

E & P COYS	ONGC	OIL		PVT.
INTEGRATED REFINING & MKTG. COYS	IOCL	HPCL	BPCL	
STAND ALONE REFINERIES	CPCL *CHENNAI*	MRPL *M'LORE*	KRL *KOCHI*	RPL *J'NAGAR*
	BRPL *B'GAON*		NRL *N'GARH*	
STAND ALONE MKTG. COYS	IBP	GAIL		PVT.

DEREGULATION - CURRENT STATUS

Completed

1. Refining sector delicensed
2. Refinery pricing on tariff adjusted import parity
3. ATF, naphtha, fuel oil etc. pricing de-controlled.

Pending

4. Freedom to source crude oil
5. International prices for domestic crude oil and gas
6. Customs duty rationalization to be completed
7. MS, HSD, Kerosene & LPG to be decontrolled (w.e.f. 1.4.02 ?)
8. Subsidies on Kerosene & LPG from general budget (w.e.f. 1.4.02 ?)
9. Decision on pipeline access
10. Regulator to be appointed

OIL & GAS COYS IN INDIA - 2001

E & P COYS	ONGC	OIL		PVT.
INTEGRATED REFINING & MKTG. COYS	IOCL	HPCL	BPCL	
STAND ALONE REFINERIES	CPCL *CHENNAI*	MRPL *M'LORE*	KRL *KOCHI*	RPL *J'NAGAR*
	BRPL *B'GAON*		NRL *N'GARH*	
STAND ALONE MKTG. COYS	IBP	GAIL		PVT.

CRUDE OIL IMPORTS

Year 2000-01: 74 MMT Rs. 66,000 crores
GOI has allowed use of hedging techniques

IOCL	Continue to be canalizing agency for import of crude oil (44 MMT) and products for oil PSUs. Strategic alliance with British Petroleum for hedging expertise
BPCL	Trading floor established. Paper trading exercises at present
HPCL	Staff under training for independent procurement of crude oil & shipping contracts
RPL	Full fledged trading floor in Mumbai with state-of-the art trading systems. Handled 25 MMT crude oil imports in 2000-01

OIL & GAS - MAJOR JOINT VENTURES

(%)

	ONGC	IOCL	HPCL	BPCL	RPL	EOL	GAIL	PIL	OTHERS
Petronet India Ltd (PIL)		16	16	16	10	10			32
Petronet Central India Pipeline Ltd. (CIPL)		26		11	26	11		26	
Petronet LNG Ltd.	12.5	12.5		12.5			12 5		50

Various other joint ventures for pipelines, LPG imports, terminals, manufacture of lubricants, power projects etc.

Retail Market Competition

	No of MS/HSD retail outlets	% share	Market share(%)		Remarks
			MS	HSD	
IOCL	7549	41.4	35.0	52.0	ATMs, IOC-Citibank co-branded credit card Convenience stores
HPCL	4600	25 1	25.6	23 6	Convenience stores, cyber cafes and ATMs Of retail outlets 56% under company control
BPCL	4562	25.0	31.8	27 0	Mckinsey & Co. retained to chalk out detailed strategy: Pure for sure QC programme. Petro bonus (MS) and Smart Flect Card (HSD) Convenience stores. Groceries. Net Shopping
IBP	1539	8 5	7.6	7 4	Nearly 50% of retail outlets in Northern India
	18250				

Use of pipeline systems

1. Pipelines are generally natural monopolies
2. Need to treat owner, operator and users as separate entities
3. Common carriage: Involves the obligation of a carrier to provide access to the capacity for which he is responsible on a pro-rata basis: for example, a new transactor requesting carriage must be accommodated, if necessary by reducing the carriage provided to other transactors.
4. Open access (contract) carriers, such as most gas pipelines, provide accessibility on a first-come first-served basis to all clients willing to pay the pipeline's maximum tariff. Once capacity is fully utilised, the carrier must refuse new clients.

EMPLOYEE PRODUCTIVITY

Coy	Refinery crude thrpt (MMT)	Sales (MMT)	Turnover Rs.crores	No. of employees	Throughput per employee (MT)
HPCL	11 98	18 39	47,180	11549	
MRPL	6 41	5.79	2,889	N A.	
BPCL	8.66	19.35	46,852	12688	
KRL	7 52	7 03	7,136	1988	3784
NRL	1.45*	1.35	837	632	
IOCL	33 22	47 79	113,327	32266	
CPCL	6 62	6 07	7,133	1712	3868
BRPL	1 48	1.31	1,255	1828	809
RPL	25 12	24 30	30,963	1123	22369
IBP	-	3 80	8,388	2626	

* Operated part year only

- Almost all companies have or are implementing Enterprise Resource Planning (ERP)
- One or two have identified large surpluses
- One or two have initiated VR schemes

Directions, Innovations and Strategies

- Lessons to be learnt on advantages of economies of scale
- PSUs need to become capital and human resources efficient
- PSUs need to use market based instruments effectively e.g. hedging for crude oil purchases
- Diversification into unrelated business areas: need to be watchful
- PSUs are and will increasingly need to focus on consumer satisfaction
- Vertical integration only if there are substantial synergies and cost savings
- Horizontal cooperation/integration can lead to considerable savings but bold steps are required
- Government as majority shareholder to initiate and facilitate the changes

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Regulatory framework for the hydrocarbons sector

Nirmal Singh, IAS, TERI

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OCC - Existing Regulator ?

- Oil price shock in 1973 - Government intervention in petroleum sector & constituting OPC
- Recommendations of the Oil Prices Committee (1975)
  - Introduce a "cost plus" pricing scheme to be implemented through a complex chain of pool accounts
  - Insulate domestic markets from the fluctuations in the international markets
  - Ensure uniform prices throughout the country

OCC - Existing Regulator ?

- OPC recommendations
  - Create a central agency to implement the elaborate pricing mechanism
  - An industry committee with a separate secretariat
  - Endowed with adequate legal powers and status
  - Autonomy in employment of expert staff

OCC is not a legal entity

OCC: Key Functions

1. Administering pricing mechanism & pool accounts
2. Co-ordinating the arrangement of transportation of crude oil imports and coastal movements
3. Inland distribution of petroleum products
4. Deciding on allocation of crude oil and product pattern of refineries based on imports, exports and national/regional demands, logistics of transportation and other allied matters

...OCC: Key Functions

5. Co-ordinate activities of downstream petroleum sector
6. Optimisation of refinery operations

Infrastructure reforms

- Increased private participation implies greater need for regulating entry and licensing to
  - Check monopolies
  - Check cartelisation
  - Ensure level playing field amongst all players

Need for a Regulator

- Upstream
  - Optimal exploitation of resources
- Downstream
  - Assuring a level playing field
    - Tariffs for common carrier pipelines - Gas/Products
    - Facilitating third party access for existing infrastructure
  - Protect consumer interests with respect to
    - Availability of products
    - Competitive prices for products

Liberalisation: Hydrocarbons Sector

- Private participation
  - Upstream ... 1980
  - Refining ... 1987
- Decanalisation of lubricants ...1992
- Parallel marketing ...1993
- Institution of
  - R- Group ... 1995
  - Expert Technical Group...1996
- Dismantling of the APM ... 1997-2002
- Delicensing of refining sector ... 1998

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Reforms : Hydrocarbons Sector

- Decision to set up a regulatory framework
  - R Group 1995
    - Regulatory body needed to ensure free & fair competition
  - Gazette Notification of November 1997
    - Pursuant to ETG recommendations
  - India Hydrocarbon Vision 2025
    - Institute authority well before deadline of April 2002

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Regulatory issues

- Harmonize conflicting interests of various stakeholders
  - Ensuring a level playing field
- Protect consumer interests w.r.t. availability of products at competitive prices
  - Prevent collusive pricing through cartelisation
  - Monitor overall product availability & ensure supply to far flung areas

International Experience: Upstream

- Ownership of resources: Government
- Need for regulation: Optimal exploitation of resources
- Regulatory tools
  - Licensing control
  - Reservoir management
  - Safety & environmental checks

International Experience

Country	Prevailing system
Norway	Norwegian Petroleum Directorate which is administratively subordinate to the Ministry of Petroleum & Energy
UK	The Oil & Gas Directorate under the Department of Trade & Industry, Government of UK
USA	Offshore: Minerals Management Service Onshore : Bureau of Land Management under the Department of Interior

...International Experience

- Upstream regulation in developing economies
  - Argentina : Energy Secretariat under the **Ministry of Economy**
  - Mexico: Absolute monopoly of Pemex under the **Ministry of Energy**
  - Thailand: Dept. of Mineral Resources under the **Ministry of Industry**
  - Venezuela: Director General Hydrocarbons under the **Ministry of Mines & Energy**

Indian Case: Existing System

Upstream

- Licensing : Ministry of Petroleum & Natural Gas
- Directorate General Hydrocarbons
  - Project facilitator
  - Regulator for reservoir management
  - Government representative in Management Committees

Indian Case: Existing System

Downstream

- Pricing and distribution
  - Ministry of Petroleum & Natural Gas through OCC
- Pricing and allocation of gas
  - Ministry of Petroleum & Natural Gas

Role of Upstream Regulator

- Government is the owner & regulation and development of fields is controlled by the Government through the Oilfields (Regulation & Development) Act
- Natural Gas / LNG
  - Primarily marketing which is a downstream activity
- No delegation of this power expected to any authority
- Upstream regulation primarily entails reservoir management

Hydrocarbon Vision 2025

"It is recommended that, though there are close linkages in the structure and technology of the upstream and downstream activities, there will be need to retain the powers of licensing areas for exploration and production with the Government for some time..."

Options ?

- Upstream regulation should remain with the Government
- DGH to continue as regulator for reservoir management
  - Statutory support: Section 32 of Petroleum & Natural Gas Rules, 1959

Downstream Regulatory Functions

- To ensure a level playing field for all operators
  - Balance the interests of the PSUs and private players
  - Balance the interests of the oil companies and consumers

Post Deregulation Scenario

- Free sourcing of crude oil (?)
- Removal of pricing and distribution control
- Dismantling of sales plan entitlement
- Decontrol of marketing activities
- Removal of subsidy on products (Except SKO and LPG)
- Liberalization of imports of petroleum products
- Deregulation of prices of natural gas

In a deregulated environment none of the key functions of the OCC relevant

... Functions: Downstream

- To regulate tariffs for pipelines used as common carrier (including those for natural gas/regassified LNG)
  - New pipeline systems: Common carriage for both pipelines & associated facilities
  - Existing associated facilities: Commercial considerations

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...Functions: Downstream

- To ensure transparency in tariff setting
  - Impact on profitability
  - Impact on consumer prices at retail end

- To analyse trends in market prices to prevent cartelisation
  - Protect consumer interests

…Functions: Downstream

- To monitor global developments of the hydrocarbons sector
  - Maintain repository of information on
    - Sales
    - Production
    - Availability
    - Import/exports
    - Demand estimates

…Functions: Downstream

- To implement Government policies

- To secure involvement of voluntary agencies and user associations to implement consumer protection measures
  - Increasing consumer awareness
    - Mass media
    - Seminars at national & state levels

...Functions: Downstream

- To regulate the allocation, transportation, distribution, and marketing of natural gas as per prevailing Government policy
  - Allocation
    - As per prevailing policy
  - Transportation & distribution
    - Tariff setting for common carrier pipelines

...Functions: Downstream

- To ensure supply of products to far-flung areas
- To intervene in crisis situations/natural calamities/wars
- To assist in planning and development of the hydrocarbons sector

Issues to be resolved before positioning the regulator

- Pipelines
  - Least cost and environment friendly mode of product movement
  - Gas can be transported only by pipelines
  - Substantial cost implications
  - Hydrocarbon Vision 2025
    - Pipelines are common carrier
  - ETG recommendations on pipelines awaiting government decision

Decision on status of pipelines

…Issues

- Inventory holding
  - Inventory holding costs are significant
  - Strategic and security considerations

Clear policy on inventory holding by all companies

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...Issues

- Retail operations
  - Retail operations for transportation fuels are conditional on Rs 20 billion investment in refining or oil exploration
  - Setting up retail operations requires lead time
  - PSUs don’t have freedom in network planning

Clear policy on retail operations

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...Issues

- Product access
  - Mismatch in refining & marketing volumes
  - Reliance on product exchange transactions & hospitality arrangements

Lead time for renegotiating existing arrangements

...Issues

- Sales tax differentials
  - – Different sales tax policies in different states
  - – Intra-state sales versus inter-state sales
    - Local sales tax
    - Central sales tax

Rationalisation of sales tax structure

...Issues

- Gas allocation
  - – Current gas allocation done by the government
  - – Ambiguity regarding the fate of the existing gas allocations

Clear allocation policy for gas users

Regulatory Authority: Structure

Upstream > **Responsibility of the Government**

Downstream

Natural Gas

Commonality of functions

Common carriage
Tariff setting
Level playing field

Structure: International Experience

- Common agencies for downstream regulation in both oil & gas
  - USA:Federal Energy Regulatory Commission
  - Canada: National Energy Board

Hydrocarbon Vision 2025

ecommended that, though there are close linkages
ructure and technology of the upstream and
eam activities, there will be need to retain the
of licensing areas for exploration and production
Government for some time
'all the activities relating to oil and gas as well as
roducts like distillates, gas hydrates, coal bed
etc. should be under one single regulatory body"

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ulatory Authority: Structure

ority for downstream and natural

t autonomous body
ed through an Act of Parliament

Instituting the Authority

- Why statutory support?
  - Its decisions will have huge financial implications
    - Needs autonomy in decision making
  - Independence from the Government
    - *Government a regulated entity through PSUs*
  - Assure confidence to private & foreign investors to attract private investment

To be created through an Act of Parliament

Interim Authority ?

- Prior legislative experience
  - Enactment involves considerable time
- Urgency in light of timeframe for full deregulation
- Draft legislation through actual experience
  - Adequate insight possible within 2-3 years

OCC as Interim Authority ?

- Staffed with PSU officials only
- Staff not trained to discharge quasi-judicial role
- A body of oil producers
- Distinction from Government
- No experience in natural gas/LNG

Independence of the regulator

- Provide freedom in functioning of the regulator by ensuring
  - A transparent selection process
  - A fixed tenure
  - Criteria for removal
  - A fair degree of financial autonomy
  - Accountability

Post deregulation...

- OCC's oil network to be retained till an alternative network is established
- Ensure a smooth transition to a deregulated environment

Skeleton OCC staff to remain for a period of 6-9 months

Previous experience in regulation

- Securities and Exchange Board of India (SEBI)
  - SEBI constituted as a non-statutory body in 1988
  - Statutory recognition in 1992 through ordinance
  - SEBI Act, 1992
- Insurance Regulatory Authority (IRA)
  - Interim IRA set up through a resolution in 1996
  - Insurance Regulatory & Development Authority Act, 1999

Options

1. Enacting fresh legislation

Prior legislative experience indicates this course could take considerable time

2. Appointment through a Cabinet Resolution

Lack of financial autonomy

All major decisions would have to be taken by the Government

...Options

3. A Control Order under the EC Act

- *Independence from the Government*
- *Immediate compliance of orders*
- *Financial authority under the EC Act*

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